LOAD FORECAST

Economics &
Forecasts Division

Corporate Planning Branch

No. 881212

LOAD FORECASTS REPORT

NO. 881212

SYSTEM DEMANDS

Load Forecasts Department
Economics and Forecasts Division
Corporate Planning Branch

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TABLE OF CONTENTS

		Page
INTRODUCTION		i
1.0	THE SHORT-TERM LOAD FORECAST - 1988 to 1993	1
1.1	Highlights	1
1.1.1	The Short-Term Primary Load Forecast	1
1.1.2	Comparison with Load Forecast 871214 - Peak Demand	2
1.1.3	Comparison with Load Forecast 871214 - Energy Demand	3
1.1.4	Comparison of Primary to Basic: 1988 Short-Term Forecast	4
1.2	Inputs to the Forecast	4
1.2.1	Regional Estimates	5
1.2.2	Economic Conditions and Trends	6
1.2.3	Short-Term Forecasting Models	7
1.3	Determining the Basic Load Forecast and the Unallocated Load	8
1.3.1	Weather	9
1.3.2	Losses	9
1.3.3	Capacity Interruptible Loads	9
1.4	Performance of Load Forecast 871214 in 1988	10
1.4.1	Actual Primary Demand Versus Forecast 871214	10
1.4.2	Weather-Corrected Primary Demand Versus Forecast 871214	12
2.0	THE LONG-TERM PRIMARY LOAD FORECAST - 1994 TO 2010	13
2.1	Highlights	13
2.1.1	Load Forecasts 881212	13
2.1.2	Comparison with Load Forecast 871214 - Peak Demand	14
2.1.3	Comparison with Load Forecast 871214 - Energy Demand	14
2.1.4	Comparison of Primary to Basic Load Forecast	15
2.1.5	Comparison of Basic Load Forecast 881212 with Basic Load Forecast 871214	16
2.1.6	Comparison of Incentive-Driven Demand Management and Load Displacement Generation, LF881212 versus LF871214	17
2.1.7	Selection of Recommended Primary Load Forecast	18
2.2	Forecast Uncertainty	19
2.3	Alternative Scenarios	21
3.0	THE LONG-TERM BASIC LOAD FORECAST - METHODOLOGY AND ASSUMPTIONS	23
3.1	Methodology	23
3.2	Discussion of Major Assumptions	24
3.2.1	Economic Trends	24
3.2.2	Energy Prices	25
3.3	Risks to the Forecast	27

TABLE OF CONTENTS (Continued)

		Page
4.0	**THE LONG-TERM BASIC LOAD FORECAST - RESULTS OF THE FORECASTING MODELS**	28
4.1	Econometric Energy Model of Ontario - EEMO	28
4.1.1	Residential Sector	28
4.1.2	Manufacturing Sector	30
4.1.3	Commercial Sector	31
4.1.4	The 1988 EEMO Forecast	31
4.2	End-Use Model Forecast	32
4.2.1	Residential Sector Forecast	34
4.2.2	Commercial Sector Forecast	39
4.2.3	Industrial Sector	42
4.2.4	Transportation Sector	47
4.2.5	The 1988 End-Use Forecast	47
5.0	**LOAD IMPACT OF INCENTIVE-DRIVEN DEMAND MANAGEMENT AND LOAD DISPLACEMENT**	49
5.1	Introduction	49
5.2	Incentive-Driven Demand Management	49
5.2.1	Electrical-Efficiency Improvement Programs	49
5.2.2	Load Shifting Programs	50
5.2.3	The Forecast	51
5.2.4	Policy Assumptions Embedded in the Forecast	54
5.3	Load Displacement Generation Forecast	54
6.0	**PERFORMANCE OF LOAD FORECAST 881212 in 1988**	73
6.1	Actual Primary Demand Versus Forecast	73
6.2	Weather-Corrected Primary Demand Versus Forecast	73
6.3	Diversity and Losses	74
6.4	Unallocated Load	75
6.5	Detail of Customer Loads	76
7.0	**UNCERTAINTY IN THE LOAD FORECAST**	77
7.1	Introduction	77
7.2	The Economic Growth Model	77
7.3	The Energy Model	78
7.4	Stochastic Simulation of GDP and Energy	78
7.5	Estimated 80% Confidence Intervals for GDP and Annual System Energy	79

TABLE OF CONTENTS (Continued)

		Page
8.0	**NEW END-USE MODELS**	81
8.1	REEPS Forecast	81
8.2	COMMEND Forecast	84
8.3	INDEPTH Forecast	86
9.0	**GLOSSARY**	88
9.1	Demand (Versus Load)	88
9.1.1	Basic Load Forecast	90
9.1.2	Primary Load Forecast	90
9.2	Diversity and Losses	90
9.3	Customers' Loads	91
9.3.1	Firm Loads	91
9.3.2	Capacity Interruptible Loads	91
9.4	Standby Power	92

INTRODUCTION

The Load Forecasts Department normally issues two load forecasts each year: a Long-Term Forecast, produced in the fall for system planning purposes; and a Short-Term Forecast, produced in early summer for revenue planning, rate development and budget purposes. The Long-Term Forecast has a time horizon of approximately 20 years.

This Load Forecast Report contains the Short-Term and Long-Term Load Forecasts approved by the Board of Directors on December 12, 1988.

The Short-Term Load Forecast for the period 1988-1993 is presented first. It was prepared using the results of:

- A customer survey carried out in the spring (called Regional Estimates);
- The updated economic forecasts based on the latest trends and anticipated changes in the economic environment;
- Electricity demand forecast models relying on the most recent data;
- The latest analysis of the deviations of recent Ontario electricity demands from last year's predictions;
- A forecast of Incentive-Driven Demand Management and Load Displacement Generation.

The Short-Term Primary Load Forecast section includes a comparison of the Primary Load Forecast with last year's Primary Load Forecast and this year's Basic Load Forecast, a discussion of Incentive-Driven Demand Management and Load Displacement Generation, and a summary of the Regional Estimates. Also provided is a brief commentary on considerations affecting the forecast, such as the economic outlook, future electricity price levels, weather effects, and the amount of electricity attributed to unallocated load and transmission losses. With the exception of unallocated load, all these factors contribute to the uncertainty associated with the forecast. The uncertainty with respect to the Short-Term Forecast is covered along with the Long-Term Forecast in Section 2.1.5. Analysis of the performance of last year's forecast, a description of the short-term forecasting models we use and the forecast of capacity interruptible loads complete the section on the short-term forecast.

The Long-Term Load Forecast for the years 1994-2010 was derived taking into account several inputs: the short-term forecast, the long-term economic outlook, econometric model (EEMO) estimates, end-use model estimates, the 1987 Load Forecast, judgmental factors, and the Incentive-Driven Demand Management and Load Displacement Generation.

The presentation of the Long-Term Primary Load Forecast is similar to that for the Short-Term. The chapter includes the results of two different approaches to forecasting, the econometric (EEMO) and end-use models, as well as two approaches to describing forecast uncertainty, a statistical confidence interval based on a new methodology and alternative load growth scenarios generated by the EEMO model using alternative macroeconomic scenarios.

Since 1986, an amount has been subtracted from the Short- and Long-Term Basic Load Forecasts to show the forecasted effects of Incentive-Driven Demand Management and Load Displacement Generation on total system demand. The

resulting forecast is the Primary Load Forecast. All notation and tables presented in his report refer to the Primary Load Forecast unless the Basic Load Forecast is explicitly noted. The Primary Load Forecast has the same role in the planning process as it always has: it is the most-likely projection of the load Ontario Hydro must plan to supply (after directly controlled loads have been netted out).

The Incentive-Driven Demand Management forecast is the estimated net impact of Marketing programs initiated by Ontario Hydro which use financial incentives to alter the level and the shape of the load. The Incentive-Driven Load Displacement Generation forecast comprises all production of electricity (other than that of Ontario Hydro) which is consumed by the generator. It is projected that these demand management strategies together will reduce energy demand by 19.2 TW.h in the year 2010, resulting in a Primary Load Forecast of 201.1 TW.h, compared with the Basic level of 220.3 TW.h.

Supplementary reports have been prepared which provide additional detail: individual customers' monthly energy for the period 1988 - 1993 and an aggregation of load for all customer classes within areas, projected to the year 2010. These reports are not printed for wide distribution because they are of limited interest to most readers. They are available in machine-readable form for users who require the data. In the past, tables for monthly customer load and primary demand for the East, West and Total Systems were provided in this report. These are no longer included, but can be obtained upon request.

1.0 THE SHORT-TERM LOAD FORECAST - 1988 to 1993

1.1 Highlights

The 1988 Short-Term Forecast is higher than the 1987 Short-Term Forecast in all forecast years. The average annual rate of growth foreseen for the 1987-1993 is approximately 4.3 TW.h or 3.1% for energy, which is 0.5% higher than the 1987 Short-Term Forecast. By 1993, primary load is forecast to be 152.3 TW.h, 4.4 TW.h higher than forecasted last year.

The Short-Term Load Forecast is prepared for the purpose of rate finalization in the fall. The change in forecast reflects the new base set by above-forecast sales for the last nine months of 1987 and the first seven months of 1988. Sales were 2.5% above the 1987 Short-Term forecast during the last half of 1987, and 3.0% above forecast for the first half of 1988, reflecting unanticipated strength in the economy. Gross domestic product growth is projected to be 3.9% in 1988, compared to the previous year's forecast of 2.9%.

The higher growth rates in the 1988 Basic Short-Term Forecast reflect the results of the monthly and annual models which incorporate updated economic projections and actual sales data. These were supported by the trend in the regional estimates, which were 1.5% higher than the 1987 Customer Survey for 1988, increasing to a 3.4% difference by 1992. The derivation of the Primary Load Forecast from the Basic takes into account the impact of incentive-driven efficiency improvement programs and time-of-use rates. In this forecast, the impact of incentive-driven load displacement generation is also netted out. Load displacement generators produce electricity for their own use and thereby reduce Ontario Hydro's electricity demand. About 250 MW of incentive-driven load displacement generation is now anticipated to be operating by 1993. The total impact of incentive-driven programs by 1993 is estimated to be 1014 MW resulting in a 3.8% reduction in the Basic Load Forecast for that year.

1.1.1 The Short-Term Primary Load Forecast

The 1988 Short-Term Primary Load Forecast for the total system is:

Table 1.1.1: Total System Primary Demand

	December 1-Hour Peak			Energy					
		Annual Growth				Annual Growth			
Year	MW	MW	%	Avg MW	TW.h	Avg MW	%	TW.h	%
Short Term									
1987 Actual	20448			14436	126.5				
1988*	22545	2097	10.3	15147	133.1	711	4.9	6.6	5.2
1989	23128	583	2.6	15631	136.9	484	3.2	3.9	2.9
1990	23597	469	2.0	16002	140.2	371	2.4	3.2	2.4
1991	24269	672	2.8	16397	143.6	395	2.5	3.5	2.5
1992*	24816	547	2.3	16887	148.3	490	3.0	4.7	3.3
1993	25445	629	2.5	17385	152.3	498	3.0	4.0	2.7
Avg Increase									
1987-1993		833	3.7			491	3.1	4.3	3.1
1988-1993		580	2.4			448	2.8	3.8	2.7

* Leap Year

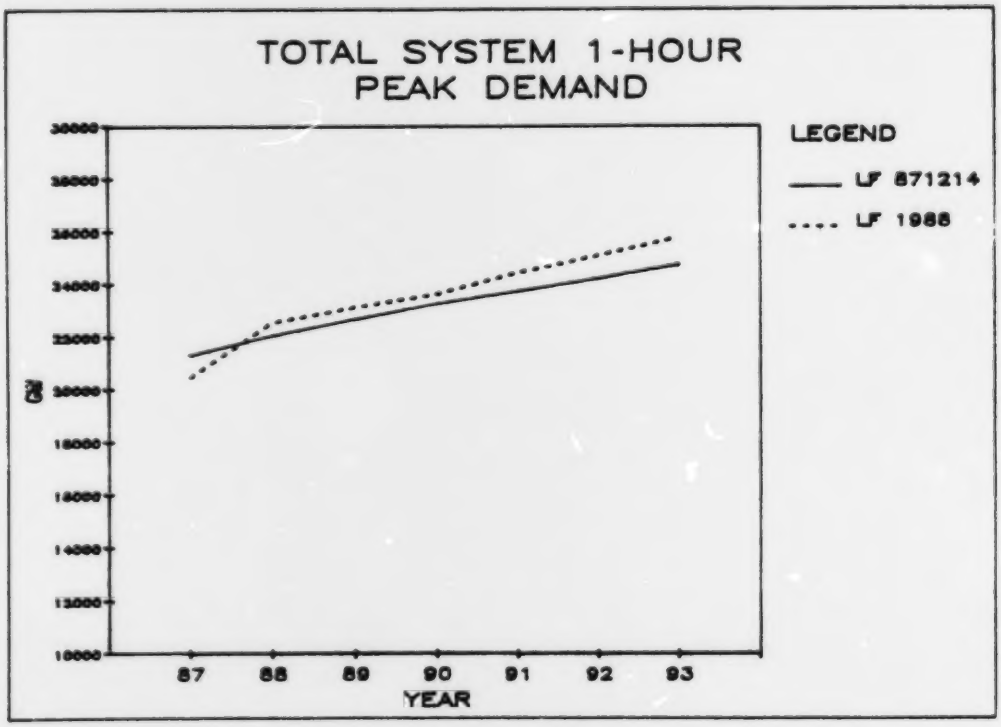
1.1.2 Comparison with Load Forecast 871214 - Peak Demand

The level of the peak forecast over the whole forecast period is 2.2% higher on average than the 1987 Short-Term Forecast. The gap between the two forecasts is at its minimum of 1.4% in 1990, the slowest growth year of the 1988 forecast. By 1993, the stronger growth in the 1988 forecast widens the difference to 2.8%.

Table 1.1.2: 1-Hour Peak Demand

December	1988 Primary Load Forecast Peak MW	1988 Primary Load Forecast % Inc	Primary Load Forecast 871214 MW	Primary Load Forecast 871214 %	Change from Primary Load Forecast 871214 MW	Change from Primary Load Forecast 871214 % Inc
1987	20448*		21314			
1988	22545	10.3	22060	3.5	485	2.2
1989	23128	2.6	22685	2.8	443	2.0
1990	23597	2.0	23271	2.6	326	1.4
1991	24269	2.8	23752	2.1	517	2.2
1992	24816	2.2	24225	2.0	591	2.4
1993	25445	2.5	24750	2.2	695	2.8
Avg % Inc						
1987-1993		3.7		2.5		
1988-1993		2.4		2.3		

*Actual



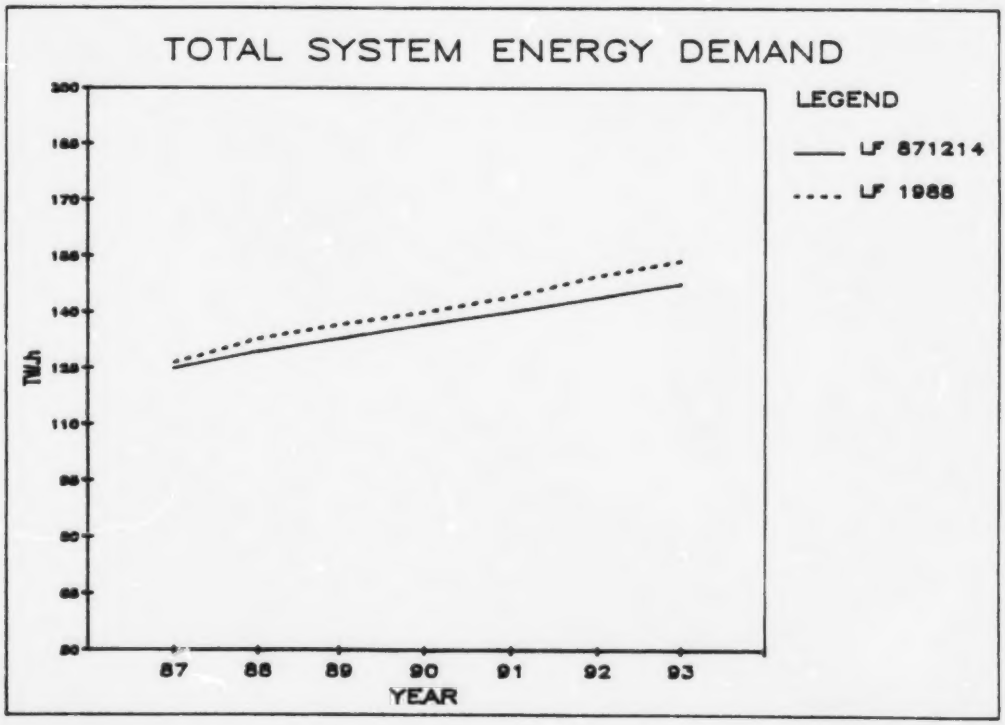
1.1.3 Comparison with Load Forecast 871214 - Energy Demand

The level of the energy forecast is approximately 2.6% higher on average than the 1987 Short-Term Forecast for the period 1988 to 1993.

Table 1.1.3: Energy Demand

	1988 Primary Load Forecast			Primary Load Forecast 871214			Change from Primary Load Forecast 871214	
Year	Avg MW	TW.h	% Inc TW.h	Avg MW	TW.h	% Inc TW.h	TW.h	%
1987*	14436	126.5		14436	126.5			
1988**	15147	133.0	5.2	14768	129.7	3.6	3.3	2.6
1989	15631	136.9	2.9	15210	133.2	2.7	3.7	2.8
1990	16002	140.2	2.5	15638	137.0	2.8	3.2	2.4
1991	16396	143.6	2.4	16037	140.5	2.6	3.1	2.3
1992**	16886	148.3	3.3	16423	144.3	2.7	4.0	2.8
1993	17385	152.3	2.7	16885	147.9	2.5	4.4	3.0
Avg % Inc								
1987-1993			3.1			2.6		
1988-1993			2.7			2.7		

* Actual
** Leap Year



1.1.4 Comparison of Primary to Basic: 1988 Short-Term Forecast

Again this year, there is a differentiation between business-as-usual system demand and that which will result after various market interventions by Ontario Hydro. Prior to 1986 the Load Forecast did not specifically include the results of these marketing efforts. The following table lists the two components of the Short-Term Load Forecast: the Basic Load Forecast that results from normal market forces including the effects on demand of Ontario Hydro's research, education and promotion activities; and the Primary Load Forecast, produced by subtracting from the Basic Load Forecast the estimated net impact of the financial incentives expected to be offered to our customers to modify their peak and energy demands.

Three major types of customer response are reflected in this forecast: peak and energy reduction as a result of incentive-driven electrical efficiency improvement programs; load-shifting from peak to off-periods due to rate structure changes (such as time-of-use rates); and, load displacement generation induced by financial incentives. Incentive-Driven Load Displacement Generation is being taken into account in the Primary Load Forecast for the first time. Non-Utility generation which is produced and consumed by the generator is considered to be a demand-side effect for planning purposes. Non-utility generation which is sold to Ontario Hydro is considered a supply-side resource.

The Primary Peak Load Forecast figures have been calculated by subtracting the December peak power reductions established for future years from the Basic Load Forecast peak demands.

Table 1.1.4: 1988 Short-Term Forecast - Primary vs Basic

	December Peak - MW				Energy - GW.h			
Year	Basic	Impact of Incentives	Primary	% Diff.	Basic	Impact of Incentives	Primary	% Diff.
1987(A)	20448	0	20448	0.0	126455	0	126455	0.0
1988	22545	0	22545	0.0	133052	0	133052	0.0
1989	23242	114	23128	0.5	137067	140	136927	0.1
1990	23839	242	23597	1.0	140542	369	140173	0.3
1991	24762	493	24269	2.0	145068	1435	143634	1.0
1992	25606	790	24816	3.1	150631	2300	148331	1.5
1993	26459	1014	25445	3.8	154930	2638	152292	1.7
Avg. % Inc								
1987-1993	4.4		3.7		3.4		3.1	
1988-1993	3.3		2.4		3.1		2.7	

(A) - Actual

1.2 Inputs to the Forecast

The short-term load forecast is prepared considering the following information.

(1) Regional Estimates - Each year a survey is made of all the Corporation's customers to determine their expectations for their own future peak demand. Known future customers are also taken into account.

(2) Economic Conditions and Trends - The most recent economic activity and energy price forecasts are assessed directly as well as used as inputs to a range of models for forecasting electricity demand.

(3) Forecasting Models - The Load Forecasts Department has estimated a variety of single-equation annual and monthly forecasting models. They range from the purely statistical analysis of past data (Box-Jenkins) to conventional structural econometric specifications. No one model has developed a clearly superior track record; methodology development is on-going.

These three sources of forecast information are supplemented by other indicators where available (such as results from the end-use models).

This section provides a brief description of each of the above inputs. The forecast models are discussed in more detail in Appendix 2.

1.2.1 Regional Estimates

To initiate the short-term forecasting process, the Load Forecasts Department asks the regional offices to provide six years of estimates of the peak for each wholesale customer (municipalities and direct industrial) and total retail customers. The regional staff, using the results from two time-series models provided by the Load Forecasts Department, together with their knowledge of the local economy and consultation with large customers, prepare an estimate for each month of the current year and the first forecast year. For the subsequent four years, only December forecasts are made.

The customers are canvassed each spring for forecasts of their own peak demands. Their estimates, which underlie the 1988 Short-Term Forecast, were 1.5% higher than the 1987 Customer Survey for 1988, increasing to a 3.4% difference by 1992.

Table 1.2.1: Sum of Customers' Loads - MW

Average Monthly 1-Hour Non-Coincident Peaks

Year	1988 Customer Survey	1987 Customer Survey	Differences	% Change
1988	19898	19599	299	1.5
1989	20799	20363	436	2.1
1990	21548	21078	470	2.2
1991	22402	21811	591	2.7
1992	23262	22492	770	3.4
1993	24127	N/A	N/A	

The municipal utilities, the area offices, and the direct customers have the best and most detailed information about plans in their own neighborhoods and businesses. They have the best perspective on new developments requiring electricity, on local business anomalies and on the continuity of existing sales. Their estimates are believed to be quite reliable for the near term.

1.2.2 Economic Conditions and Trends

Economic Outlook

The North American economy continues to outperform expectations. In fact, U.S., Canadian and Ontario growth rates are all very similar with the consumer sector, manufacturing and the services industries (real estate and trade) providing the major stimulus at present. Nonetheless a moderating trend is now in evidence and this weakness is expected to intensify, bringing real provincial growth from 3.9% in 1988 to 2.7% in 1989 and further to 2.3% in 1990. Debt burdened consumers are gradually tightening their purse strings in the face of higher interest rates. Here in Ontario, the real estate market has stabilized, residential construction activity has declined and capital investment is not as robust as it has been. A projected softening in car sales on both sides of the border and flagging export volumes will soon impact manufacturing output. Transitional problems associated with the introduction of bilateral free trade (aggravated by the strong Canadian dollar) will further limit growth possibilities over the next few years. Nonetheless, Ontario growth is still projected to exceed national growth because of the more rapid increases in provincial population and because of an expected rebound in manufacturing investment.

The following table shows the Economics and Forecasts Division's Canadian and Ontario output projections.

Table 1.2.2: Economics and Forecasts Division's Outlook

Gross Product - $1971 Billion

	Canada				Ontario			
Year	1987 Sept.	% Increase	1988 Sept.	% Increase	1987 Sept.	% Increase	1988* Sept.	% Increase
1987	175.4	2.9	177.5	3.9	63.9	3.5	71.2	4.2
1988	180.2	2.7	184.2	3.8	65.7	2.9	74.0	3.9
1989	185.6	3.0	188.7	2.4	67.8	3.2	76.0	2.7
1990	191.2	3.0	192.6	2.1	69.7	2.8	77.7	2.3
1991	196.9	3.0	199.0	3.3	72.2	3.6	80.4	3.5
1992	202.8	3.0	206.0	3.5	74.4	3.0	83.5	3.8
1993	208.9	3.0	212.2	3.0	76.6	3.0	86.0	3.0

* Historical numbers revised

Energy Price Trends

Real electricity prices are projected to remain almost constant in real terms for the next few years. Electricity's price competitiveness relative to both fuel oil and natural gas deteriorated in recent years - especially in the 1986/1987 period when weak crude oil prices and deregulation of the natural gas market resulted in lower retail prices for both fuels in Ontario. Little change in electricity's relative price is projected for the rest of the 1980's and the early 1990's.

1.2.3 Short-Term Forecasting Models

The following paragraphs provide a brief outline of the single-equation models built with annual and monthly load data that the Load Forecasts Department currently prefers. Greater detail concerning model development, specification and forecasts is given in Appendix 2 of a separate report on the Short-Term Load Forecast issued in September 1988, which is available on request.

i) Monthly Models

For several years the Load Forecasts Department has been gaining experience with several more advanced forecast modelling techniques. These use monthly data and comprise single and multiple variable time series methods as well as a regression technique that focuses on modelling patterns in the remaining error terms.

Since January 1988, the Load Forecasts Department has adopted a weather-correction methodology which adjusts for wind speed, illumination and humidity in addition to the temperature effects previously taken into account. This methodology was used to create a historical time-series of monthly weather-corrected data that goes back to 1971. The models estimated by EPRI's FORECASTMASTER software using these data had considerably better fits than in the past.

The single variable time series model, called the Box-Jenkins technique after the original developers, presumes that all the information relevant to predicting the future of a variable is contained within the data history of the series to be predicted. Box-Jenkins models may be expected to forecast well in periods when the factors which affect the variable being forecasted continue their recent trend. For economic data this is unlikely to be longer than about two years and is often considerably less time. Predicted changes to the background environment of the forecasted variable that are out of keeping with recent trends will not be reflected in the projection made by the Box-Jenkins model.

Multivariate time series methods are an elaboration of the single variable technique which permit key causal variables to be included in the forecasting equation. The form of multivariate time series analysis in Forecast Master which is used by the Load Forecasts Department is called State-space modelling. The state-space model's forecast is still dominated by recent patterns in electricity use; a forecasted change in the trend of GDP growth has noticeably less impact on the forecast than the same change would have in one of the annual econometric models.

The third monthly modelling technique is known as 'Auto Pro'. This methodology is a hybrid of standard regression techniques and the time series methods used by the other two model types just described. It is not as responsive to external shocks, such as a marked economic slow down, as the pure econometric techniques used to fit the annual models.

The forecasts have picked up the recent strength in electricity sales and are projecting between 4.4% and 5.2% average growth for the period 1987 to 1993.

ii) Annual Models

A review of single equation econometric models of primary energy sales was conducted early in 1988. These models were evaluated on the basis of goodness-of-fit, ex post forecasting performance and economic properties. All depend heavily on real Ontario GDP. They, therefore, were quite sensitive to the upward revision to the estimated level for Ontario GDP in 1987 and the forecast for 1988 contained in the September 1988 Economic Outlook. The forecasted increase in 1988 is offset by weaker growth in both 1989 and 1990. The sharp slowdown in the pace of economic activity forecasted for these two years is followed fairly well by the models, though as noted below, other factors may be at work to bring about an even sharper reduction in load growth rates.

The estimated average annual growth rates of electric energy for the period 1987 to 1993 of our preferred models ranged from 3.2% to 3.7%.

1.3 Determining the Basic Load Forecast and the Unallocated Load

The customer surveys, economic trends and forecast model results constitute most of the data used in generating the forecast, but any other indicators of economic performance and electricity sales are considered as well. The forecast considers all available information taking into account the suitability of each methodology for projecting particular years of the forecast period.

To reconcile the total of the customer estimates to the Basic Load Forecast, an amount may be added or subtracted. This amount is called unallocated load.

In April 1988, the short-term load forecast for 1988 and 1989 was updated for the OEB Hearings. The additional information available since the update was made suggested only minor changes to the projection for these two years. The increase of 2.5% for 1988 above the LF871214 was made taking into account the following: that the very strong (9%) year-over-year growth result for the first quarter was due in large part to a very weak first quarter in 1987 combined with weather factors; that the weather-corrected year-over-year growth for the months of April to July averaged 3.7% and exhibited a distinct declining trend; and, that the model forecasts suggested an increase of roughly that amount was in order, especially when greater weight is assigned to the annual models.

The decision to make only small changes to the load growth rates for 1989 and 1990, despite the model results which tend to call for stronger growth in those years, was made considering the nature of the reduction in economic growth forecasted for those years. The years 1986-88 have been characterized by stronger than anticipated economic growth driven by a massive investment boom, especially centred in new housing and commercial building construction. As new building stock is a significant contributor to load growth, the declining growth rates for this component of GDP suggest a more marked contraction in load growth at this stage of the business cycle than is reflected in the GDP growth rate itself. The load growth rate was kept the same, on average, for 1989-90 even though the GDP forecast is down 0.5% in each year from the September 1987 Economic Outlook. A further increase in the electricity to GDP ratio in those years was not considered warranted, given the investment trend.

After 1990, the recommended forecast is slightly lower than that prepared by our customers and those produced by the annual models. Nonetheless, it

constitutes a significant upward adjustment to the 1991-93 forecast. The increase may largely be attributed to the increase in GDP expected in 1992-3 as a result of the Free Trade Agreement. Further increases in the forecast would be premature and run the risk of over-reacting to the under-forecasts of the past few years. The electricity intensity of the economy begins to decline again in this period.

Table 1.3: Sum of Customers' Loads - MW

Average Monthly 1-Hour Peaks

Year	Customer Survey	Unallocated Load	1988 Short-Term Load Forecast
1988	19898	144	20042
1989	20799	-103	20696
1990	21548	-267	21281
1991	22402	-364	22038
1992	23262	-432	22830
1993	24127	-565	23562

The amounts of unallocated load shown in the table are less negative than those used in last year's report.

1.3.1 Weather

The expanded Short-Term Forecast includes monthly forecasts of energy and peak demand. The monthly actual demands, as well as the annual actual totals, are strongly influenced by weather conditions. For the purpose of the forecast, normal weather conditions, as measured by the recorded averages, are assumed. For example, the December peak is assumed to occur on the most extreme weather day in December, which is assumed to have temperature, wind and illumination conditions equal to the typical extreme day in December.

1.3.2 Losses

In addition to estimates of customer demand, transmission losses are incorporated in the Basic Load Forecast. These losses averaged approximately 4.0% of customer energy for the period 1981 to 1983. Since 1984 losses have been gradually increasing, reaching 4.6% in 1987. These higher than average losses will continue for a few more years due to the delay in obtaining approval for adequate transmission out of the Bruce nuclear complex. There will be no relief from this situation until the new 500 kV line from Bruce to London is brought into service, currently scheduled for August 1, 1990.

Forecast losses are assumed to be 4.6% for the years 1988 and 1989, 4.5% in 1990 and 4.3% for the remaining years of the forecast.

1.3.3 Capacity Interruptible Loads

In general, capacity interruptible loads are those for which a customer contracts for power which may be interrupted by Ontario Hydro in exchange for a lower rate. Interruptible loads and Control Centre Controlled loads are subtracted from the Primary Load Forecast when System Planning derive their Planning Firm Load series.

Table 1.3.3: Capacity Interruptible Loads - East System

Sum of Non-Coincident Customers' Capacity Interruptible Load
December Monthly Peak - MW

	1988	1989	1990	1991	1992	1993
Interruptible						
25 Hz	9	9	28	28	28	28
60 Hz	841	831	844	928	941	957
Total	850	840	872	956	969	985
In Terms of Generation*						
25 Hertz MW	7	7	22	22	22	22
60 Hertz MW	657	650	659	699	735	748
Total	664	657	681	747	757	770

* At time of East System Peak

Currently only one customer in the West System has a capacity interruptible contract. West System's December Interruptible load in terms of generation is as follows:

1988 - 32 MW
1989 - 32 MW
1990 - 32 MW
1991 - 32 MW
1992 - 32 MW
1993 - 32 MW

1.4 Performance of Load Forecast 871214 in 1988

As noted in Section 5.1, the Load Forecast is prepared assuming normal weather conditions. Actual weather conditions may deviate significantly from normal for a short period, though usually they are not a large factor affecting annual energy. Annual peak, however, is quite weather-sensitive. Performance of the forecast is most appropriately measured against the weather-corrected actuals.

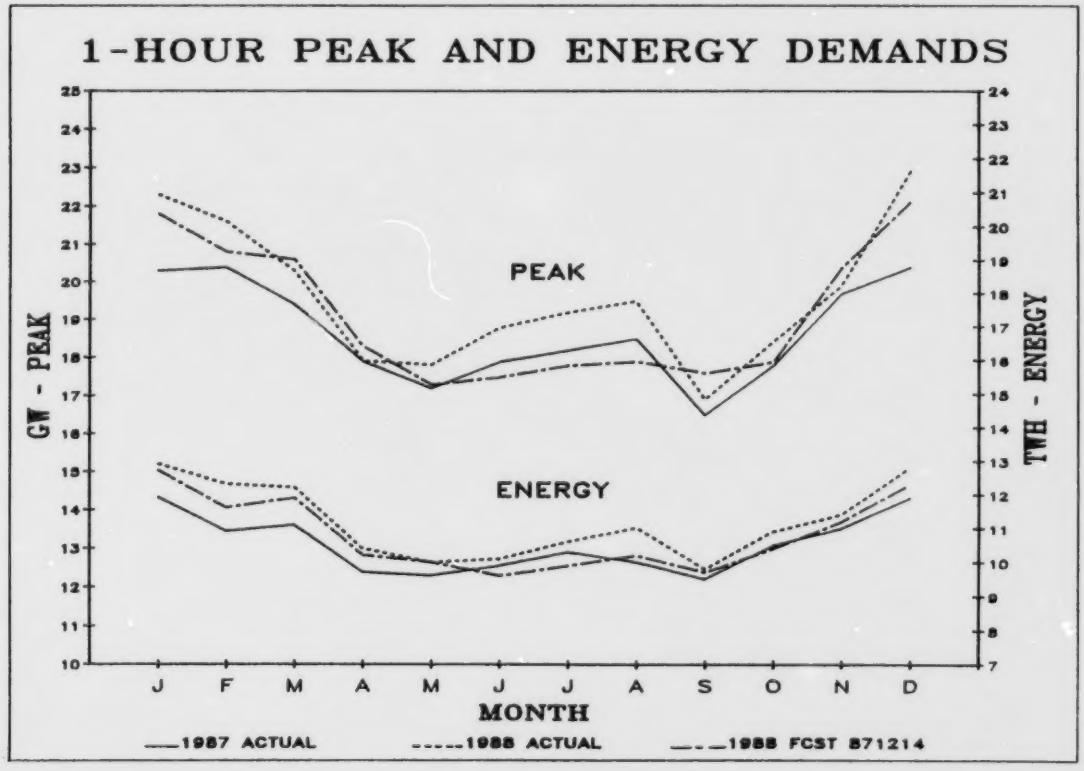
1.4.1 Actual Primary Demand Versus Forecast 871214

This section evaluates the performance of last year's forecast against the actual monthly peak and energy data for 1988. With the exception of the 1-hour peak for March, April, September and November, the Load Forecast 871214 under-forecasted demand. The greatest deviations from the forecast were for the months of June, July, and August, when the weather was very hot and humid. For the year 1988, the actual demand was, on average, 2.1% greater in peak and 3.6% greater in energy than the Load Forecast 871214.

Table 1.4.1: Load Forecast Performance

	1-Hour Peak - GW					Energy - TW.h				
	Actual		% Yr/Yr	1988 Forecast	% *	Actual		% Yr/Yr	1988 Forecast	% *
	1987	1988	Growth	871214	Dev.	1987	1988	Growth	871214	Dev.
Jan	20.3	22.3	9.9	21.8	2.5	11.9	12.9	8.7	12.7	1.7
Feb	20.4	21.6	5.8	20.8	3.5	10.9	12.3	12.3	11.6	6.2
Mar	19.4	20.3	4.5	20.6	-1.6	11.1	12.2	9.6	11.9	2.0
Apr	17.9	17.9	0	18.3	-1.9	9.7	10.4	7.0	10.2	2.0
May	17.2	17.8	3.7	17.3	3.1	9.6	10.0	4.5	10.0	0.2
Jun	17.9	18.8	5.2	17.5	7.7	9.9	10.1	2.6	9.6	5.7
Jul	18.2	19.2	5.7	17.8	8.1	10.3	10.6	3.0	9.9	7.0
Aug	18.5	19.5	5.1	17.9	8.6	10.0	11.0	9.7	10.2	7.8
Sep	16.5	16.9	2.5	17.6	-3.8	9.5	9.8	2.5	9.7	1.0
Oct	17.8	18.4	3.2	17.9	2.5	10.5	10.9	3.5	10.4	4.6
Nov	19.7	19.9	1.0	20.4	-2.4	11.0	11.4	3.2	11.2	1.8
Dec	20.4	22.9	12.2	22.1	4.0	11.9	12.8	7.3	12.3	3.8
Avg	18.7	19.6	5.0**	19.2	2.1**	126.5+	134.4+	6.3**	129.7+	3.6**

* Per cent deviation from forecast.
\+ Total
** Based on annual average



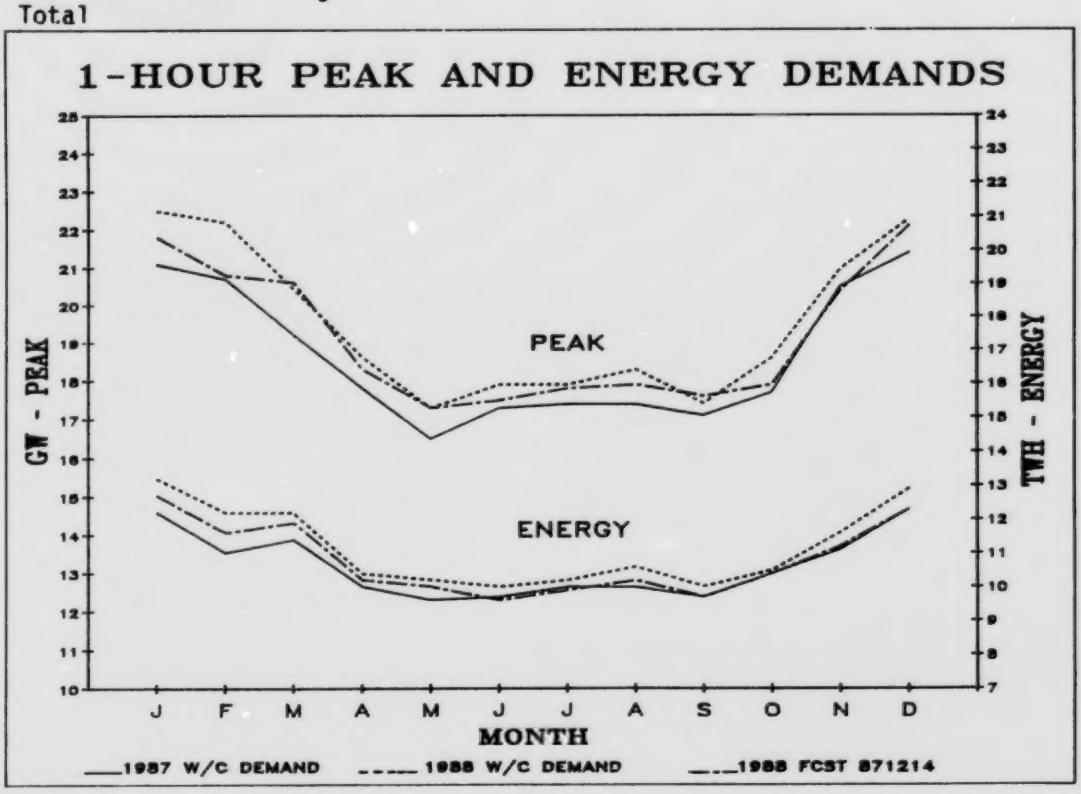
1.4.2 Weather-Corrected Primary Demand Versus Forecast 871214

Table 1.4.2 below summarizes the monthly performance of Load Forecast 871214 in 1988 on a weather-corrected basis.

Table 1.4.2: Load Forecast Performance

	1-Hour Peak - GW					Energy - TW.h				
	Weather Corrected Demand		% Yr/Yr	1988 Forecast	%	Weather Corrected Demand		% Yr/Yr	1988 Forecast	%
	1987	1988	Growth	871214	Dev.*	1987	1988	Growth	871214	Dev.*
Jan	21.1	22.5	6.6	21.8	3.4	12.2	13.2	7.7	12.7	3.4
Feb	20.7	22.2	7.4	20.8	6.5	11.0	12.2	11.1	11.6	5.9
Mar	19.2	20.4	6.0	20.6	-1.1	11.4	12.2	6.9	11.9	2.5
Apr	17.8	18.6	4.0	18.3	1.6	10.0	10.4	3.6	10.2	1.8
May	16.5	17.3	4.8	17.3	0.2	9.6	10.2	5.8	10.0	1.5
Jun	17.3	17.9	3.4	17.5	0.4	9.7	10.0	3.6	9.6	4.8
Jul	17.4	17.9	2.9	17.8	0.8	10.0	10.2	1.6	9.9	2.5
Aug	17.4	18.3	5.0	17.9	2.1	10.0	10.6	5.8	10.2	4.1
Sep	17.1	17.4	1.8	17.6	-1.1	9.7	10.0	2.9	9.7	3.1
Oct	17.7	18.6	4.9	17.9	5.6	10.4	10.5	1.1	10.4	0.9
Nov	20.5	21.0	2.4	20.4	2.9	11.1	11.6	3.7	11.2	3.1
Dec	21.4	22.3	4.4	22.1	1.1	12.3	12.9	4.6	12.3	4.6
Avg	18.7	19.5	4.6**	19.2	1.9**	127.6+	134.1+	5.1**	129.7+	3.4**

* Per cent deviation from forecast
** Based on annual average
\+ Total



2.0 THE LONG-TERM PRIMARY LOAD FORECAST - 1994 to 2010

2.1 Highlights

The recommended 1988 Primary Load Forecast is slightly lower in both peak and energy terms in the years 2000 and 2010 than the 1987 Primary Load Forecast.

It is important to recognize that this result masks increases in the Basic Load Forecast of 3.8% and 5.2% in the years 2000 and 2010 respectively. These are more than offset by the increase in the expected impact of incentive-driven demand management and load displacement generation on the Primary Load Forecast. (See Section 1.4 for clarification of terminology.) The increase in the Basic Load Forecast is the net result of several positive and negative factors. Those contributing to a higher forecast included higher actual load in 1987, faster GDP growth than in last year's forecast, due largely to the expected impact of the Free Trade Agreement, and new modelling results. Reducing the forecast were the significantly higher electricity prices now projected for the long term.

2.1.1 Load Forecasts 881212

Table 2.1.1: Long-Term Primary Load Forecast - 881212

	December 1-Hour Peak			Annual Energy		
		Annual* Growth			Annual* Growth	
Year	MW	MW	%	TW.h	TW.h	%
Short Term						
1987(A)	20448			126.5		
1988	22545	2097	10.3	133.1**	6.6	5.2
1989	23128	583	2.6	136.9	3.9	2.9
1990	23597	469	2.0	140.2	3.2	2.4
1991	24269	672	2.8	143.6	3.5	2.5
1992	24816	547	2.3	148.3**	4.7	3.3
1993	25445	629	2.5	152.3	4.0	2.7
Long Term						
1995	26252	531	2.3	158.2	2.9	1.9
2000	27918	355	1.3	171.2	2.6	1.6
2005	30793	575	2.0	188.2	3.4	1.9
2010	32889	419	1.3	201.1	2.6	1.3

(A) - Actual

	Average Annual Growth			
Period***	MW	%	TW.h	%
1987 - 1990	1050	4.9	4.6	3.5
1987 - 1995	726	3.2	4.0	2.8
1987 - 2000	575	2.4	3.4	2.4
1987 - 2005	575	2.3	3.4	2.2
1987 - 2010	541	2.1	3.2	2.0

* Values for long term are for five-year period ending in year specified.
** Leap Year
*** Using actual 1987 values

2.1.2 Comparison with Load Forecast 871214 - Peak Demand

The level of the peak forecast over the period to 1993 is 2.4% higher on average than the 1987 Short-Term Forecast. The gap between the two forecasts is at its minimum of 1.4% in 1990, the slowest growth year of the 1988 forecast. By 1993, the stronger growth in the 1988 forecast widens the difference to 2.8%.

As the impact of incentive-driven demand management and load displacement generation cumulates, it begins to offset the underlying increase in the Basic load by about 1997. Beyond the year 2000, there is no further reduction in peak which may be accommodated on the system due to load-shifting and the impact of efficiency-improvement programs has been scaled down. These factors account for the reduction in the difference between the 1987 and 1988 forecasts beyond the turn of the century.

Table 2.1.2: December 1-Hour Peak Demand

Year	1988 Recommended Primary Load Forecast (MW)	Primary Load Forecast 871214 (MW)	Increase Over 871214 MW	Increase Over 871214 %
Short Term				
1987	20448 (Actual)	21314		
1988	22545	22060	485	2.2
1989	23128	22685	443	2.0
1990	23597	23271	326	1.4
1991	24269	23752	517	2.2
1992	24816	24225	591	2.4
1993	25445	24750	695	2.8
Long Term				
1995	26252	25773	479	1.9
2000	27918	28370	-452	-1.6
2005	30793	30907	-114	-0.4
2010	32889	33106	-217	-0.7
Growth Rates				
1987 - 2000	2.4	2.2		
1987 - 2005	2.3	2.1		
1987 - 2010	2.1	1.9		

2.1.3 Comparison with Load Forecast 871214 - Energy Demand

The level of the energy forecast is approximately 2.7% higher on average than the 1987 Short-Term Forecast for the period 1988 to 1993.

By 1998, the impact of incentive-driven electrical efficiency improvement programs and load displacement generation are forecasted to have cumulated sufficiently to offset the increase in the Basic Load Forecast. The impact by the year 2000 on Primary Energy results in a reduction of 0.5% in load versus LF871214. The increase in Basic load growth outpaces the increase in incentive-induced energy reduction for the next five years pushing Primary Energy up slightly by 2005. Basic load growth is about the same for 2005 - 2010 as it was in the LF871214; the small fall in Primary in this time period is due to a modest increase in incentive-driven energy reductions.

Table 2.1.3: Primary Energy Demand

Year	1988 Recommended Primary Load Forecast (TW.h)	Primary Load Forecast 871214 (TW.h)	Increase Over 871214 TW.h	Increase Over 871214 %
Short Term				
1987	126.5 (Actual)	125.2	1.2	1.0
1988*	133.1	129.7	3.3	2.6
1989	136.9	133.2	3.7	2.8
1990	140.2	137.0	3.2	2.3
1991	143.6	140.5	3.1	2.2
1992*	148.3	144.3	4.1	2.8
1993	152.3	147.9	4.4	3.0
Long Term				
1995	158.2	155.5	2.7	1.7
2000	171.2	172.0	-0.8	-0.5
2005	188.2	187.7	0.5	0.3
2010	201.1	201.4	-0.3	-0.1
Growth Rates				
1987 - 2000	2.4	2.5		
1987 - 2005	2.2	2.3		
1987 - 2010	2.0	2.1		

* Leap Year

2.1.4 Comparison of Primary to Basic Load Forecast

Again this year, there is a differentiation between business-as-usual system demand and that which will result after various market interventions by Ontario Hydro. The following table lists the two components of the Load Forecast: the Basic Load Forecast that results from normal market forces including the effects on demand of Ontario Hydro's research, education and promotion activities; and the Primary Load Forecast, produced by subtracting from the Basic Load Forecast the estimated net impact of the financial incentives expected to be offered to our customers to modify their peak and energy demands.

Three major types of customer response are reflected in this forecast: peak and energy reduction as a result of incentive-driven electrical efficiency improvement programs; load-shifting from peak to off-peak periods due to rate structure changes (such as time-of-use rates); and, load displacement generation induced by financial incentives. The latter is being taken into account in the Primary Load Forecast for the first time. Load displacement generation is non-utility generation which is produced and consumed by the generator. It is considered to be a demand-side effect for planning purposes. Non-utility generation which is sold to Ontario Hydro is considered a supply-side resource.

The Primary Peak Load Forecast figures have been calculated by subtracting the December peak power reductions established for future years from the Basic Load Forecast peak demands.

Table 2.1.4: 1988 Load Forecast - Primary vs Basic

	December Peak - MW				Energy - GW.h			
Year	Basic	Impact of Incentives	Primary	% Diff.	Basic	Impact of Incentives	Primary	% Diff.
Short Term								
1987(A)	20448	0	20448	0.0	126455	0	126455	0.0
1988	22545	0	22545	0.0	133052	0	133052	0.0
1989	23242	114	23128	0.5	137067	140	136927	0.1
1990	23839	242	23597	1.0	140542	369	140173	0.3
1991	24762	493	24269	2.0	145068	1435	143634	1.0
1992	25606	790	24816	3.1	150631	2300	148331	1.5
1993	26459	1014	25445	3.8	154930	2638	152292	1.7
Long Term								
1995	27766	1514	26252	5.4	162524	4341	158183	2.7
2000	31455	3537	27918	11.2	184122	12959	171164	7.0
2005	34944	4151	30793	11.9	204543	16317	188226	8.0
2010	37638	4749	32889	12.6	220309	19160	201149	8.7
Growth Rates								
1987-1993	4.4		3.7		3.4		3.1	
1987-1995	3.9		3.2		3.2		2.8	
1987-2000	3.4		2.4		2.9		2.4	
1987-2010	2.7		2.1		2.4		2.0	
1990-2000	2.8		1.7		2.7		2.0	
2000-2010	1.8		1.7		1.8		1.6	

(A) - Actual

2.1.5 Comparison of Basic Load Forecast 881212 with Basic Load Forecast 871214

The 5.1% increase in the 1988 Basic Load Forecast in the year 2010 relative to the 1987 Basic Load Forecast may be attributed to three factors: the increase in the base year, changes in economic variables driving the forecast and model changes. The level of Ontario GDP forecast for 2010 is 4.6% higher than last year. Given the implicit assumption of constant return to scale in the Econometric Energy Model of Ontario (EEMO)*, that would translate in an increase in load of about 4.6%. Electricity prices are forecast to be 11% higher by 2010 than they were projected to be in 1987. The long-run own price elasticity of -.38 implicit in EEMO suggests this would reduce load by about 4.2%, other things equal. The net increase in load therefore, is largely due to the upward shift of the base and a multiplicity of model changes which change the electricity-to-output ratio in the models. Substantial model development to both the econometric and end-use modelling systems was undertaken in 1988.

* A detailed description of this model is found in Section 4.1.

Table 2.1.5: Basic Load Forecast Comparison

Year	December One-Hour Peak - GW: Load Forecast 871214	Load Forecast 881212	Difference GW	%	Energy - TW.h: Load Forecast 871214	Load Forecast 881212	Difference TW.h	%
Short Term								
1987 Actual	20.45	20.45	0	0	126.46	126.46	0	0
1988	22.06	22.55	0.49	2.2	129.72	133.05	3.33	2.6
1989	22.77	23.24	0.47	2.1	133.26	137.07	3.81	2.9
1990	23.44	23.84	0.40	1.7	137.05	140.54	3.49	2.5
1991	24.02	24.76	0.74	3.1	140.62	145.07	4.45	3.2
1992	24.68	25.61	0.93	3.8	144.53	150.63	6.10	4.2
1993	25.41	26.46	1.05	4.1	148.40	154.93	6.54	4.4
Long Term								
1995	26.89	27.77	0.88	3.3	157.03	162.52	5.50	3.5
2000	30.37	31.46	1.09	3.6	177.36	184.12	6.76	3.8
2005	33.30	34.94	1.65	4.9	194.46	204.54	10.09	5.2
2010	35.87	37.64	1.77	4.9	209.49	220.31	10.82	5.2
Growth Rates								
1987 - 1993	3.7	4.4			2.7	3.4		
1987 - 1995	3.5	3.9			2.7	3.2		
1987 - 2000	3.1	3.4			2.6	2.9		
1987 - 2010	2.5	2.7			2.2	2.4		
1990 - 2000	2.6	2.8			2.6	2.7		
2000 - 2010	1.7	1.8			1.7	1.8		

2.1.6 Comparison of Incentive-Driven Demand Management and Load Displacement Generation, LF881212 versus LF871214

The projected impact of incentive-driven load displacement generation was not available for the 1987 Load Forecast. Its inclusion reduces primary load significantly over the entire forecast period. ('Natural' load displacement has always been netted out within the Basic Load Forecast.)

The LF871214 estimate for the impact of electrical efficiency improvement programs in the year 2000 was 1000 MW. In the course of the year, the Corporation announced its intention to achieve a 2000 MW reduction in peak due to these programs by the year 2000. The full achievement of this objective has been included in the forecast, subject to some caveats which are outlined in Section 2.6.2.4.

The ability of the power system to make use of 16-hour load-shifting is still set at 1000 MW in the year 2000. The full amount could be achieved by time-of-use rates, though it is assumed that other incentive programs might play a role, especially where the new rate structure is not available to the consumer directly. The time distribution of the impact has been altered slightly since last year, but not its end result.

Table 2.1.6: Comparison of Cumulative Load Impact of Incentive-Driven Demand Management and Load Displacement, LF881212 vs LF871214 (December Peak MW)

Year	LF881212 L-S/ EIP*	LF881212 LD**	LF881212 Total	LF871214 Total***	Difference in Total
Short Term					
1989	94	20	114	85	29
1990	214	28	242	172	70
1991	341	152	493	265	228
1992	547	243	790	455	335
1993	763	251	1014	660	354
Long Term					
1995	1215	299	1514	1115	399
2000	3000	537	3537	2000	1537
2005	3390	761	4151	2390	1761
2010	3765	984	4749	2765	1984

* Load Shifting (Time-of-Use) and Efficiency Improvement Programs, called in the past Indirect Incentives

** Load Displacement

*** Includes Load Shifting and Efficiency Improvement Programs, but no Load Displacement

2.1.7 Selection of Recommended Primary Load Forecast

The recommended Primary Load Forecast is derived by subtracting the forecast of incentive-driven demand management and load displacement generation from the recommended Basic Load Forecast. The latter is determined considering as inputs the long-term load forecasts produced by the Econometric Energy Model of Ontario (EEMO) and the End-Use Model. Both are spliced onto the Short-Term Load Forecast for 1988 - 1993.

The recommended Total System Basic Load Forecast growth rate lies approximately at the mid-point of the growth rates of the two model forecasts and was selected considering the judgments of the econometric and end-use modelers. It was the judgment of the econometric modelers that their commercial sector forecast was, if anything, too high. The end-use forecast for the commercial sector was deemed too low in light of the insights gained by running COMMEND, the new EPRI end-use model for that sector. As a result, the recommended Basic Load Forecast represents, for the most part, an adjustment to the commercial sector forecasts of both models.

Table 2.1.7: Summary of Forecasts

Year	Ontario Hydro Basic Energy Demand Model Comparison (TW.h) EEMO*	End-Use*	Official Load Forecast 881212 (TW.h) Basic	Impact of EIP***	Load Displacement	Primary
1987 Actual	126.5	126.5	126.5	0.0	0.0	126.5
1988	131.2	132.6	133.1	0.0	0.0	133.1
1990	139.7	139.9	140.5	0.2	0.2	140.2
1995	164.0	159.7	162.5	2.2	2.1	158.2
2000	187.8	178.6	184.1	9.2	3.8	171.2
2005	208.4	194.4	204.5	11.0	5.3	188.2
2010	228.7	209.6	220.3	12.3	6.9	201.1
Growth Rates**						
1987 - 2000	3.1	2.7	2.9			2.4
1987 - 2005	2.8	2.4	2.7			2.2
1987 - 2010	2.6	2.2	2.4			2.0

* Econometric Energy Model of Ontario and End-Use Model Forecasts are described in Section 4.

** Average annual percent change

*** Incentive-driven Electricity Improvement Programs

2.2 Forecast Uncertainty

For many years historical load forecast performance has served as the basis for calculating the statistical uncertainty associated with the Basic Load Forecast. The resulting 60% confidence bands have been extremely wide. The 1987 uncertainty band for the year 2000 was 16 GW wide relative to a median forecast of about 30 GW. By 2010, the 60% band was about 35 GW wide relative to a forecast of 37 GW. There has been some concern expressed over the years, both internally and, most recently, externally, that this spread was excessive and implausible.

This year the Economics and Forecasts Division undertook several studies to investigate alternative methodologies for calculating the load forecast uncertainty band. The band presented in Table 2.2 and plotted in Figure 2.2 represents the recommended 80% uncertainty band which has emerged from this research. The decision to present an 80% band, rather than a 60% band, reflects a preference for planning purposes expressed by the Corporation's System Planners.

The selected methodology determines the uncertainty associated with the GDP forecast. A projection of load then follows and, hence, the GDP uncertainty is translated into load uncertainty. The results indicate that statistical uncertainty grows very rapidly in the early years of the forecast period to around 6% of the median forecast and then doubles as a percent of the median in the next ten years. In the final ten years the bandwidth increases in absolute terms but declines in percentage terms.

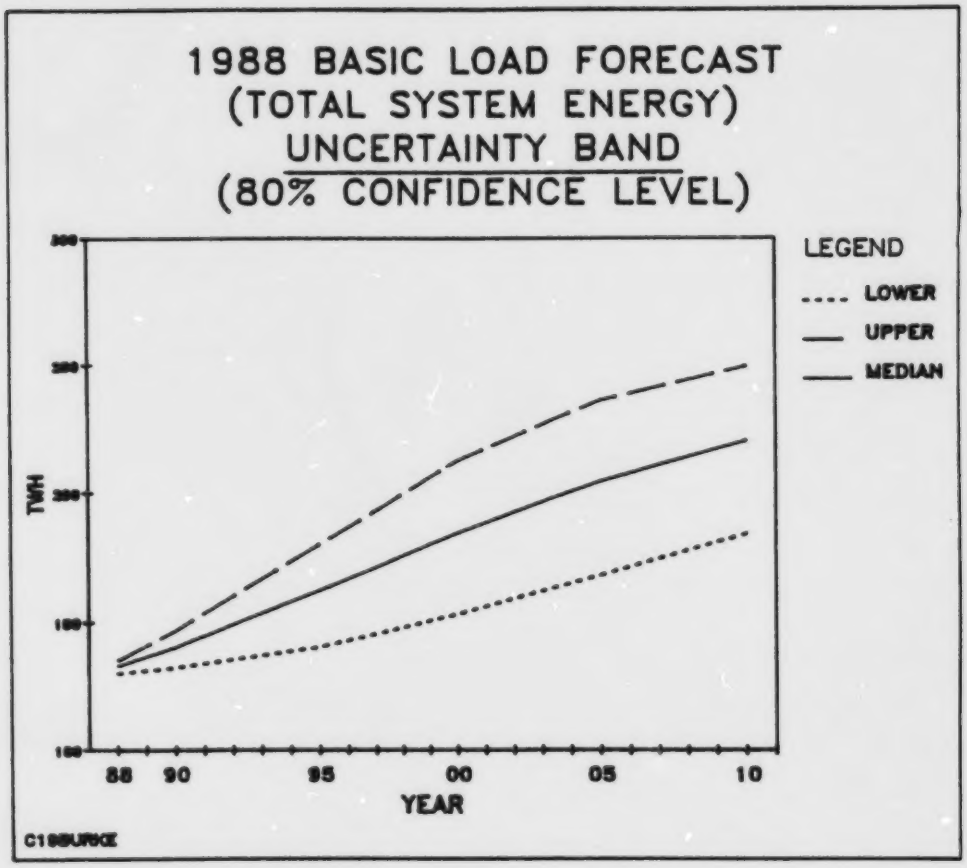
The lower bound of the uncertainty band is set at the 10% point of the distribution about the median load forecast. This means that for any particular year there is a 10% chance that the load will actually fall below the value given for that year. Similarly there is a 10% chance that the load will actually exceed the value given by the upper band.

The new 80% band has a width of about 60 TW.h in the year 2000 and 65 TW.h in the year 2010. This translates into a width of 10 GW in the year 2000 and 11 GW in the year 2010, assuming no uncertainty in the system load factor.

Table 2.2: Uncertainty Band for Annual Basic Energy (TW.h)

Year	Lower (10%)	Forecast (50%)	Upper (90%)
Short Term			
1987 (Actual)		126.5	
1988	130.4	133.1	135.3
1989	131.6	137.1	141.7
1990	132.5	140.5	146.9
1991	134.5	145.1	153.9
1992	137.6	150.6	162.2
1993	138.0	154.9	169.2
Long Term			
1995	140.6	162.5	180.3
2000	153.3	184.1	212.4
2005	168.4	204.5	236.2
2010	184.5	220.3	249.5
Growth Rates			
1987 - 1993	1.5	3.4	5.0
1987 - 2000	1.5	2.9	4.1
1987 - 2005	1.6	2.7	3.5
1987 - 2010	1.7	2.4	3.0

Figure 2.2



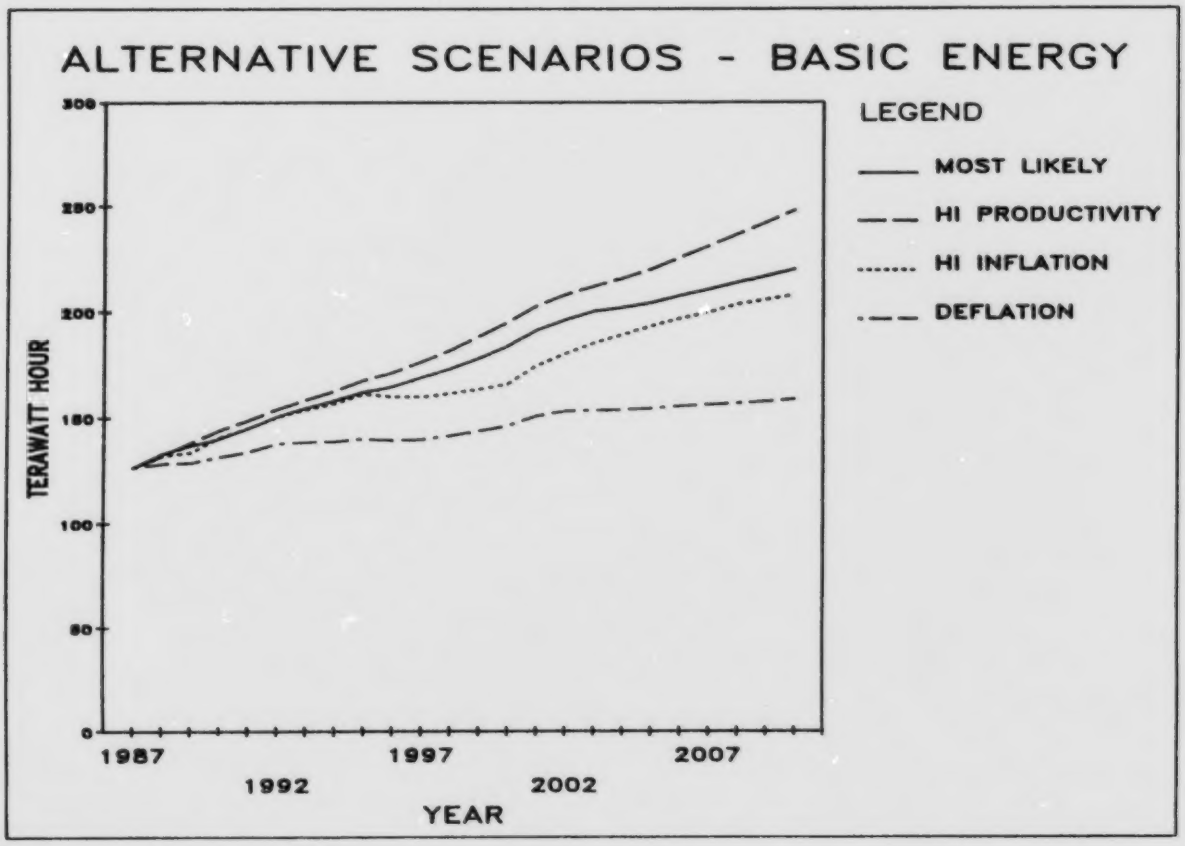
2.3 Alternative Scenarios

Alternative load growth scenarios are generated in order to gauge the risk of a major change in the assumed economic growth rates. The alternative economic scenarios are prepared by the Economic Forecasts section and EEMO is run to estimate their impact on energy demands. The three scenarios postulated are called Higher Productivity, Higher Inflation and Deflation. One limitation of these scenarios is that the same real electricity prices are used in all cases. When further information on the costs of the other scenarios is available, they will be re-estimated. The energy demand growth rates for these scenarios, as well as the most-likely scenario, are given below.

Table 2.3: Alternative Scenarios

Basic Energy
Annual Growth (%)

Year	Higher Productivity	Most Likely	Higher Inflation	Deflation
1987 - 1993	3.9	3.4	3.3	1.5
1987 - 1995	3.6	3.2	3.1	1.3
1987 - 2000	3.4	2.9	2.1	1.1
1987 - 2010	3.0	2.4	2.2	1.0
1990 - 2000	3.1	2.7	1.7	1.1
2000 - 2010	2.4	1.8	2.3	0.8



3.0 THE LONG-TERM BASIC LOAD FORECAST - METHODOLOGY AND ASSUMPTIONS

3.1 Methodology

The methodology used to prepare the long-term load forecast is evolving to meet Ontario Hydro's changing planning needs. In particular, the emphasis on incentive-driven demand management has significant consequences for the effort placed on development of detailed end-use modelling systems. The inclusion of demand management in Hydro's supply/demand planning strategy has led to new terminology, as well. The definitions of these terms are also likely to evolve as the intricacies of demand-side planning are sorted out. The Basic Load Forecast is a projection of the load Ontario Hydro expects to serve under market conditions where there are no interventions by Ontario Hydro in the form of incentives. For the purpose of this forecast, long-standing Hydro activities such as research, education and promotion, which transfer information (but not money), are assumed to be part of the normal operation of the marketplace. The Primary Load Forecast is derived from the Basic by netting out the impact of financial incentive-driven demand management and load displacement generation programs. The methodology used to derive the Primary from the Basic Load Forecast is described in Section 2.1.4.

This section confines itself to the methodologies used to prepare the Basic Load Forecast. In general terms, two approaches are taken to estimating electricity demand in Ontario: 'top-down' econometric modelling and 'bottom-up' end-use modelling. Both attempt to capture the effect of a large number of demographic, economic, energy market and technological factors on electricity demand in the long run. Because they do so at different levels of aggregation, the techniques available for extrapolation into the future differ.

The econometric approach relies on statistical analysis of past energy consuming behavior and forecasts of broad economic aggregates to generate estimates of future electricity requirements. The end-use approach tends to be so specific that historical data sets may not be available for statistical analysis. Instead, expert opinion on key technology or market trends are combined with very detailed forecasts of activity levels in end-use categories to derive the forecast. However, as data quality and detail improve and estimation techniques become more sophisticated, econometric results may increasingly determine many specific end-use forecasts. The hard distinction that once existed between engineering end-use (or process) models and econometric models is becoming less clear cut. The need for the load forecast to be tied to a broad scenario for the economy and at the same time be sufficiently detailed to be useful for analyzing demand management programs is pushing methodology to a common ground. The result will exploit the best of both worlds.

Ontario Hydro uses both end-use and econometric modelling systems in preparing the long-term Basic Load Forecast. The strengths and weaknesses of these models are reconciled judgmentally in order to arrive at a recommended forecast for planning purposes.

The econometric forecast of electricity demand in Ontario is produced by EEMO, the Econometric Energy Model for Ontario (the energy module of the former EDEM system). EEMO takes as inputs forecasts of 13 final demand categories for the Ontario economy provided by the Economic Forecasts Section. These are processed by input/output and energy/output matrices in the course of deriving

industrial and commercial sector energy demands. Forecasts of electricity and other fuel prices contribute to projecting electricity's future market shares. The residential sector electricity forecast depends critically on the demographic forecast which is used to derive the economic outlook. Some of the model's major equations are described below in Section 1.3.1.

The end-use forecasting model which has been operating for several years at Ontario Hydro serves as a large accounting system for residential, commercial and industrial energy use. Forecasts of sub-sector activity levels, fuel market shares, penetration rates and technology changes must be provided in order for the model to derive end-use electricity demands. The Load Forecasts Department has also been adapting to the Ontario context a set of more sophisticated end-use models developed by the Electric Power Research Institute. The residential model known as REEPS (Residential Energy End-Use Planning System) and the commercial model, called COMMEND, have both been simulated this year in parallel with the existing models. They incorporate econometric equations to produce some of the market share and technology choice results which formerly had to be determined outside the end-use model.

The use of more than one model allows the forecaster to take into account more of the available information about the past in order to assess the future. Any differences between the forecasts are instructive, since they can be traced directly to the model or to the underlying assumptions. This gives the forecaster the ability to ensure consistency and the validity of the final forecast recommended.

3.2 Discussion of Major Assumptions

The three most important factors in any model of the demand for electricity in the long run are the projections of the general level of economic activity, the price of electricity and the prices of other competing fuels. These factors can be incorporated into the models and the forecasting procedure in any of several ways. Because these factors are so central, each of the models has been run using similar assumptions. This approach allows the model results to reflect important differences in other kinds of assumptions, and helps the forecaster to understand the sources of the differences. The economic and energy price trends used throughout the load forecast are summarized below.

3.2.1 Economic Trends

Economic growth will follow the path outlined in the most-likely forecast of the Economics and Forecasts Division's Economic Outlook, Annual Review 1988. This outlook predicts real economic growth in Ontario averaging about 2.65% per year over the period 1987 to 2010. Following the trends in population growth, the economic growth rate is forecasted to slow down steadily.

Ontario population will grow at an average annual rate of 0.8% to the year 2010, taking population to just over 11.5 million.

Ontario labor force will grow at an average annual rate of 1.1% to the year 2010, when it will be over 6 million.

Commercial floorspace will increase from its present level of 2.4 billion square feet to 3.1 billion square feet by 2010, an average annual rate of increase of 1.1%.

Housing stock is projected to grow at 1.5% per annum to 2010, from 3.42 million in 1987 to 4.84 million in 2010.

The outlook assumes that the stability of social, economic, and financial institutions will be retained. No international financial crisis will seriously affect the Canadian financial system. There will be no major supply disruptions in basic commodities, like fuels.

The 1988 Annual Economic Outlook forecasts a level of Gross Domestic Product (GDP) in Ontario of almost $131 billion (1971 dollars) in 2010, an increase of 4.6% over last year's economic outlook. The increase is the result of a slightly higher population projection, the effect of the Free Trade Agreement and a more upbeat outlook for the province's industries. The inflation outlook has been lowered from last year's, which reflects a continuation of relatively restrictive monetary policy.

Table 3.2.1: **Economic Outlook**

	Ontario Real GDP (Millions of 1971$)				Ontario Consumer Price Index (1981 = 100)			
	Fall 1987	%*	Fall 1988	%*	Fall 1987	%*	Fall 1988	%*
1988	70,980	2.9	74,074	3.9	150.4	5.8	146.5	4.5
1990	75,302	2.8	77,823	2.3	169.8	6.0	160.6	4.6
1995	88,489	3.2	91,098	3.2	216.7	5.0	200.1	4.5
2000	100,508	2.5	104,586	2.8	283.2	5.5	255.4	5.0
2005	112,611	2.3	117,754	2.4	370.1	5.5	333.8	5.5
2010	124,942	2.1	130,648	2.1	495.3	6.0	426.1	5.0

*Annual Growth Rate 1988 and 1990, 5-year annual average 1995-2010.

3.2.2 Energy Prices

Table 3.2.2: **International and Domestic Energy Prices - Reference Case Real 1988 Dollars**

	Wholesale Prices			Ontario Retail Prices - Residential		
	International Oil Persian Light - F.O.B. US$/Bbl	Domestic Oil ORAC Cdn$/Bbl	Natural Gas (Toronto) Cdn$/Mcf	Fuel Oil ¢/L	Natural Gas $/Mcf	Electricity ¢/kW.h
1988	14.90	20.65	3.35	32.9	5.95	5.75
1990	16.90	23.60	3.40	33.25	5.70	5.80
2000	23.40	31.40	4.80	38.0	7.40	5.60
2010	26.40	35.60	5.45	40.7	8.30	5.50

Source: Retail Energy Price Trends, October 1988

The structure of the international oil market and its short-term problems have remained almost unchanged since the 1986 oil price collapse. OPEC's ability to adjust its output at times when the market weakens has remained the most important determinant of market stability in the near term. During the first

three quarters of 1988, with the cartel producing more than the effective demand for its oil in world markets, crude oil prices were under downward pressure. In general, our most likely price forecast and its underlying assumptions have not changed much from last year: weakness for the rest of the 1980s is projected to be followed by upward pressure in the 1990s. Although in the short term our crude oil price forecast has been revised downward, by the year 2005 it is almost the same, in real terms, as last year.

The domestic oil market is expected to continue to be deregulated so that Canadian wholesale oil prices are projected to fluctuate with the trend in the international oil prices, in practice with West-Texas Intermediate crude at Chicago, subject to exchange rate and transportation adjustments. By the year 2005, our current forecast for Ontario Refiners Acquisition Cost (ORAC) is about 4% lower, in real terms, than last year's forecast.

The Canadian natural gas market made substantial steps toward deregulation in 1987 and 1988 and now operates in a more market-oriented environment. However, the market is still dominated by the regional distributors and the major beneficiaries of the new system are the industrial customers. Residential and commercial customers' bills have been declining since 1985 and are expected to increase only moderately for the next two years.

A major uncertainty for the future natural gas market in Canada is the Canada-U.S. Free Trade Agreement. With continued deregulation in both Canada and the United States and free trade in energy between the two countries, the combination of a tighter U.S. market for gas and the increasing cost of marginal supplies in the United States is expected to drive up the price of gas in both the United States and Canada. The natural gas price forecast has remained almost unchanged.

In the current "Reference Case" forecast, electricity prices are still projected to rise on average below the rate of inflation for the entire forecast period, though they are much closer to a zero real rate of increase than last year. By the year 2005, the average residential rates are, in real terms, only about 4.5% below the 1988 level. Electricity's price competitiveness relative to natural gas has deteriorated, especially over the last two years, and this trend is expected to continue for another couple of years. However, the long-term energy price trends are still expected to be characterized by gradual improvement in electricity's relative price.

There is a two way relationship between future electricity prices and the load forecast. For example, a forecast of low electricity prices will, other things being equal, produce a relatively high forecast for electricity demand. However, this will in turn imply a need for capacity sufficient to meet that demand which will cause costs and, therefore, electricity prices to increase. To take this feedback loop into account several iterations took place with the Financial Planning Department to ensure consistency between electricity prices generated by that department's Financial Planning Model and the electricity forecasts from the econometric model. (The end-use forecast was sufficiently close to the Reference Case that no iteration was required.) The prices in Table 3.2.2 refer to the starting point of these iterations.

3.3 Risks to the Forecast

The principal risks identified for the Basic Load Forecast include variations in the rate of real economic growth, the Ontario Hydro rate levels and structure and the prices of other fuels.

In the forecast, as reported in this document, some of the risks associated with these uncertainties are addressed by the use of three alternative scenarios (in addition to the most likely). Each scenario shows the impact on system demand of a set of coordinated alternative assumptions about economic growth (including population growth) and energy prices. The scenarios allow some explicit consideration of the outcomes possible given underlying conditions different from those envisioned in the central forecast. The forecasts of electricity demand made for each of these scenarios indicate a wide range of risk arising from the economic outlook alone.

The Basic Load Forecast includes the impact of Ontario Hydro's research, education and promotion programs on electricity sales. As noted above, a projection of the size and effectiveness of Ontario Hydro's incentive-driven demand management is obtained independently of the Basic Load Forecast. These estimates are netted out of the Basic Load Forecast figures to obtain the Primary Load Forecast. Therefore, any uncertainty associated with the forecast of these marketing targets will directly affect the uncertainty of the Primary Load Forecast. However, it is too early to be able to quantify this effect. Therefore, the bandwidth surrounding the Basic Load Forecast is applied to the primary load forecast as well.

Given the sources of external uncertainty, in addition to the uncertainty attached to the load forecasting process itself, the necessity for care in the use of the load forecast cannot be overstressed. The load forecast cannot be used as only a single number; the sources and consequent ranges of forecast error must be considered as well.

For this reason, the band of error associated with the forecast is as important as its central tendency.

4.0 THE LONG-TERM BASIC LOAD FORECAST - RESULTS OF THE FORECASTING MODELS

To quantify the effects of the complex network of factors that determine energy demand in the longer term, the results from the econometric and end-use models are both analyzed. The long-term forecast is then integrated with the short-term forecast and final adjustments based on judgment are made. The resulting forecast is referred to as the Basic Load Forecast.

4.1 Econometric Energy Model of Ontario - EEMO

EEMO evolved from EDEM (Econometric Demographic Energy Model) which up to this year was the long-run econometric model used for load forecasting. EDEM had its own demographic, macro-economic and energy modules. The demographic module is now run separately. The economic module has been blended into an improved Ontario economic model now known as LISA. The energy module has been updated with current data and re-estimated equations. The program was changed to allow the various sectors to stand alone and be forecasted separately. This new energy model was named EEMO.

LISA (Long-Term Impact and Simulation Analysis model) is a dynamic econometric model which has been estimated using annual data for Ontario from 1961 to 1986. It produces the long-term Ontario GDP forecast as well as the final demand categories needed by EEMO.

Forecasts are produced for components of consumption, investment and government spending, as well as exports, imports, and inventories. When these expenditure components are added they give a forecast of GDP in Ontario. The model is also used to produce the alternative scenarios for Ontario that are used for corporate planning.

Forecasts are produced to 2010, and are tuned to the forecasts in the Short-Term Economic Outlook. The long-term forecasts are the same as those published in the Long-Term Economic Outlook.

The energy model is designed to forecast long-term growth rates rather than fluctuations around this trend. The forecasts from LISA, therefore, are smoothed before they are used by the Load Forecasts Department in the energy model.

An important determinant of long-term growth in LISA is the demographic forecast that it uses. The downward trend in Ontario GDP growth comes partially from the declining forecast for Ontario population.

EEMO is a sectoral econometric model. The relationship between energy consumption and the variables which determine the level of this consumption has been estimated for the period 1962 to 1986. EEMO predicts the level of consumption for Ontario as a whole by individual fuel -- electricity, natural gas, oil and coal -- and by consuming sector -- residential, commercial and industrial. The major factors which influence the level of consumption are fuel prices and scale factors, such as the number of households and the level of output.

4.1.1 Residential Sector

The residential demand for electricity is modelled by considering separately (a) the demand for energy-using appliances (saturation) and (b) the intensity of use of the appliance stock (usage). Two indexes have been developed to

reflect those concepts. They consider 13 major appliance types including electric space heating and water heating.

The aggregate saturation index (ELSAT) is defined as:

$$ELSAT_t = \frac{\sum_{i=1}^{13} USE71_i * SAT_{it}}{\sum_{i=1}^{13} USE71_i * SAT_{i71}}$$

where: $USE71_i$ is the 1971 kW.h usage for appliance i

SAT_{it} is the proportion of household with appliance i in year t

The aggregate use index (ELUSE) is then defined as:

$$ELUSE_t = \frac{ELRES_t}{\sum_{i=1}^{13} USE71_i * SAT_{it}}$$

where: $ELRES_t$ is electricity consumption per household in year t

The estimated equation for ELSAT is a partial adjustment model of the prices of electricity, natural gas and oil and income per household. The aggregate use index is also estimated in partial adjustment form with the price of electricity and income per household as explanatory variables. Also included in this equation are a time trend and a dummy variable derived from federal CHIP grants whose purpose is to account for the increased conservation since the mid-1970's. The elasticities are shown in the following table.

Table 4.1.1.1: Estimated Price and Income Elasticities in the Residential Sector

	ELSAT		ELUSE	
	Short-Run	Long-Run	Short-Run	Long-Run
Price of Electricity	-0.18	-0.43	-0.09	-0.11
Price of Natural Gas	0.12	0.29	N/A	N/A
Price of Oil	0.03	0.07	N/A	N/A
Income per Household	0.24	0.57	0.33	0.42

The use index was increasing over the period 1962 to 1972 - an era of falling or fairly constant real electricity prices and increasing income per household. From 1973 to the present when real electricity prices were rising and there was a strong push towards energy conservation the use index gradually declined at an average annual rate of 0.7%. Over the forecast period to 2010 a continued decline is projected, but at a slightly lower rate.

The aggregate saturation index has also grown over the entire historical period. Three distinct phases may be identified: 1) fairly steady growth from 1962 to 1972, corresponding to the period of declining or constant real electricity prices and increasing income; 2) faster growth from 1973 to 1978, reflecting the increasing substitution into electricity and the drop in electricity prices relative to oil; and (3) slower growth rates for the period

1979-1987, due to low growth in income per household (as a result of the 1982 recession), and average positive growth of electricity prices relative to gas. This index is forecast to continue to grow until 2010 at an average rate of 0.8% per annum, as favorable electricity prices and steady income growth are projected.

Forecasts of the saturation and use indices together with their explanatory variables and the resulting forecast of residential electricity consumption are given below:

Table 4.1.1.2: Residential Electricity Forecast

Year	ELSAT*	ELUSE*	Electricity (GW.h)	Total Energy (GW.h)	Market Share (%)
1987	108.2	97.5	34,726	106,831	32.5
1990	108.7	96.9	36,993	113,443	32.4
2000	122.6	94.2	47,110	127,906	36.8
2010	129.0	87.1	51,795	134,484	38.5

* 1980 = 100

The combined effect of the forecasts of the saturation and use indices is that residential electricity consumption grows strongly over the forecast period, but the rate of growth steadily declines after 2000, reflecting trends in the demographic forecast, less favorable electricity prices, and slower growth in personal income. Total residential energy is forecast to grow much more slowly than electricity due primarily to strong and persistent increases in the real prices of oil and natural gas. As a result, the market share of electricity in the residential sector shows an increasing trend - from 32.7% in 1987 to 38.5% by 2010.

4.1.2 Manufacturing Sector

The demand for electricity in the manufacturing sector is estimated in a two-stage optimization procedure. In the first stage, a translog cost share model is estimated for four fuels (electricity, natural gas, fuel oil and coal). This formulation calculates the cost minimizing mix of fuel shares. In the second stage a total energy equation is estimated as a function of price and a measure of what manufacturing energy would have been if technological progress and productivity remained at their 1971 levels. The equation is estimated in double log form and includes a dummy variable to reflect the pulp and paper strike in the mid-seventies. Implicit to the model is the assumption of constant returns to scale. This assumption was tested and the null hypothesis was not rejected. The long-run electricity price elasticity is at -0.28 and those for natural gas and fuel oil are -0.48 and -0.70 respectively.

For the forecast period, electricity prices are projected to be fairly constant and, after an initial sharp decrease, the prices of oil and natural gas are projected to increase in real terms through the forecast period. Consequently, electricity market share increases from 20.6% in 1987 to 22.5% by 2010. Because of the high costs of mitigating the environmental consequences of coal combustion, the forecast was prepared with an increasing real effective cost of coal. The energy requirements displaced by coal were picked up by natural gas, for the most part, and to a lesser extent electricity.

Table 4.1.2: Electricity Market Share in Manufacturing Sector

Year	Electricity (TW.h)	Growth Rate *	Energy (TW.h)	Growth Rate *	Market Share (%)
1987	41.9	-	202.8	-	20.6
1990	45.9	-	223.5	-	20.5
1995	51.8	2.4	245.8	1.9	21.1
2000	58.6	2.4	268.4	1.8	21.8
2005	65.8	2.3	295.1	1.9	22.3
2010	74.8	2.6	333.2	2.5	22.5

* Average annual percentage change for five year period

4.1.3 Commercial Sector

The commercial sector is modelled much like the manufacturing sector in that a total energy equation and a translog cost share system are estimated. The main difference is that instead of disaggregating energy into four fuel types, electricity is treated separately and all other fuels are lumped together.

Constant returns to scale is implicit again. The own-price elasticities for electricity are -0.23 and -0.40 in the short and long runs respectively.

As is shown in Table 4.1.3, the market share for electricity is projected to increase to 38.2% by 2010. This is due to the steady improvement in electricity's price competitiveness over the long term.

Table 4.1.3: Electricity Market Share in Commercial Sector

Year	Electricity (TW.h)	Growth Rate *	Total Energy (TW.h)	Growth Rate*	Market Share (%)
1987	41.9	-	117.8	-	35.5
1990	49.0	-	141.2	-	34.7
1995	60.3	4.3	170.0	3.8	35.5
2000	71.7	3.5	192.4	2.5	37.3
2005	80.7	2.4	211.4	1.9	38.2
2010	89.4	2.1	234.1	2.1	38.2

* Average annual growth rate for five year blocks

4.1.4 The 1988 EEMO Forecast

The EEMO forecast is higher than the load forecast which underlies the Reference Electricity price forecast. After several iterations with the Financial Planning Department, the electricity price forecast which emerges that is consistent with the EEMO forecast is about 5% higher than the reference case in 2010.

The EEMO forecast results project that total residential electricity use will increase at a compound rate of 1.8% over the period 1988 to 2010 - about .8 percentage points less than the growth rate of total electricity demand. In fact, the rate of growth of residential demand follows a downward trend from the late 1990s on, due to the slowing down of population growth, which continually pulls down the rate of growth of total electricity demand.

The commercial sector has faster growth rates for both total energy and electricity than the residential sector. Its electricity growth averages 3.2% a year for the period 1988 to 2010. Electricity's share of the commercial market grows from 35.5% in 1987 to 38.2% in 2010. (Note: The EEMO and end-use definitions of the commercial and residential sectors are not identical.)

In the industrial sector (manufacturing and mining), electricity growth averages about 2.5% a year between 1988 and 2010, while total energy grows slightly more slowly.

In order to derive the Basic Load Forecast from the sum of the three sectoral forecasts, own (load displacement) generation is subtracted out and other adjustments, mainly line losses, added on. The load displacement that is expected as a result of normal market forces is described in the section on incentive-driven load displacement generation.

Table 4.1.4: EEMO 1988 Forecast

Year	Resi-dential	Com-mercial	Industrial	Own** Generation	Adjust-ments***	EEMO Basic Electric Energy
	TW.h	TW.h	TW.h	TW.h	TW.h	TW.h
1987 Actual	34.7	41.9	46.8	3.7	6.8	126.5
1988	35.1	44.8	48.2	3.7	6.8	131.2
1990	36.8	49.0	50.8	4.1	7.1	139.7
1995	42.9	60.3	57.2	4.2	7.7	164.0
2000	47.1	71.7	64.9	4.8	8.9	187.8
2005	50.4	80.7	72.7	5.2	9.8	208.4
2010	51.8	89.4	82.5	5.6	10.6	228.7
Growth Rates*						
1987-1990	2.0	5.4	2.8			3.4
1987-1995	2.7	4.7	2.5			3.3
1987-2000	2.4	4.2	2.5			3.1
1987-2005	2.1	3.7	2.5			2.8
1987-2010	1.8	3.3	2.5			2.6

* Average annual percent change

** Own generation is co-generated electricity that is produced and consumed by industry

*** Ontario Hydro losses less Ontario electricity not sold by Hydro (excluding own generation)

4.2 End-Use Model Forecast

End-use modelling uses a "bottom up" approach to energy analysis. It starts with the initial stock of energy using devices and an estimate of future demand for the services of these devices. The energy conversion efficiency of existing equipment, penetration of new technologies with typically higher efficiency and relative fuel share for each end use are analyzed at a highly disaggregated level. Trends in consumption pattern per household, floor-area and industrial process are combined with sectoral activity forecasts to arrive at the final demand estimate.

Each of the major energy using sectors is modelled separately. This analysis requires forecasts of sectoral activity levels such as residential housing stock, commercial floorspace and industrial output. The key sectoral activity forecasts were derived by the Economic Forecasts Section in a manner consistent with the Economic Outlook, 1988 Annual Review. To meet the extensive data requirements of the end-use models, this Section produced 12 commercial floorspace forecasts, 30 industrial output forecasts in physical units, and a forecast of construction in the residential sector. To produce these forecasts econometric relationships were developed using explanatory factors such as population, labor force, disposable income, and service and industrial sector GDP forecasts at the two-digit level.

As in the past, Ontario Hydro's End-Use Model (EUM) served as the framework for the above analysis. The results from this model are the basis of the information presented in the following sections.

In addition to work on the EUM, extensive work was carried out on the new generation of end-use forecasting models obtained from EPRI --- REEPS, COMMEND and INDEPTH. For the first time, forecasts using these newer models were produced and were used to provide valuable insights into the updating of the existing EUM. Although detailed results of these new models are not presented here directly, they played an important role in this year's forecasting exercise.

These newer models provide a level of sophistication beyond the simplistic "accounting approach" utilized by the EUM. The choice, energy efficiency and utilization of electricity consuming equipment are modelled directly by these models using basic economic principles of cost minimization and consumer behavior. In addition, fuel prices are an explicit input. Neither of these two properties is present in the current EUM.

The table below compares the sectoral growth rates obtained using the EPRI models with those obtained using the EUM. The results obtained are seen to agree quite well. Long-term results (past 1993) only are shown. Comparisons in growth during the short term would not strictly be valid since customer surveys which were used for the short-term forecast were also used as input to tune the EUM during the 1988 - 1993 period. No such intervention was used with the EPRI models which were allowed to simulate all forecast years independently.

In fact, the general agreement between the two sets of models is not surprising given that the richer analytical capabilities of the newer models were used to update assumptions used in the EUM. It is expected that the newer EPRI models will be used directly for the 1989 end-use forecast.

Table 4.2: Comparison with New EPRI Models

Residential	End-Use	REEPS
1993 - 2000	2.1	2.0
1993 - 2010	1.7	1.7
Commercial	**End-Use**	**COMMEND**
1993 - 2000	2.1	2.4
1993 - 2010	1.8	2.2
Industrial (Cement)	**End-Use**	**INDEPTH**
1993 - 2000	2.1	2.4
1993 - 2010	1.5	1.8

4.2.1 Residential Sector Forecast

Housing Stock

The main driving variable in the Residential sector is the housing stock. Projections of the housing stock construction rates are made by the Economic Forecasts Department using household and population per household forecasts. This forecast is in the form of total construction starts on a yearly basis. This forecast is then broken down into completions by building type by the Load Forecasts Department. This year's housing completion forecast is as follows:

Table 4.2.1.1: Annual Additions to Housing Stock (000's)

Year	Single Det.	Semi/Duplex	Row	Apartment	Total
1987	54955	3385	5111	21349	84800
1990	48160	2018	7654	20257	78089
1995	42007	1907	6720	17983	68617
2000	36176	1548	6082	16039	59845
2005	35202	1492	5747	15382	57823
2010	34457	1429	5427	14784	56097

With this completion forecast, the resulting total stock projections show stock growing at about 2% per annum to the year 1995 and then slowing down gradually to roughly 1% per annum by the year 2005. Over the entire forecast period, total stock grows by about 1.5% per year. See Table 4.2.1.2.

Figure 4.2.1.1

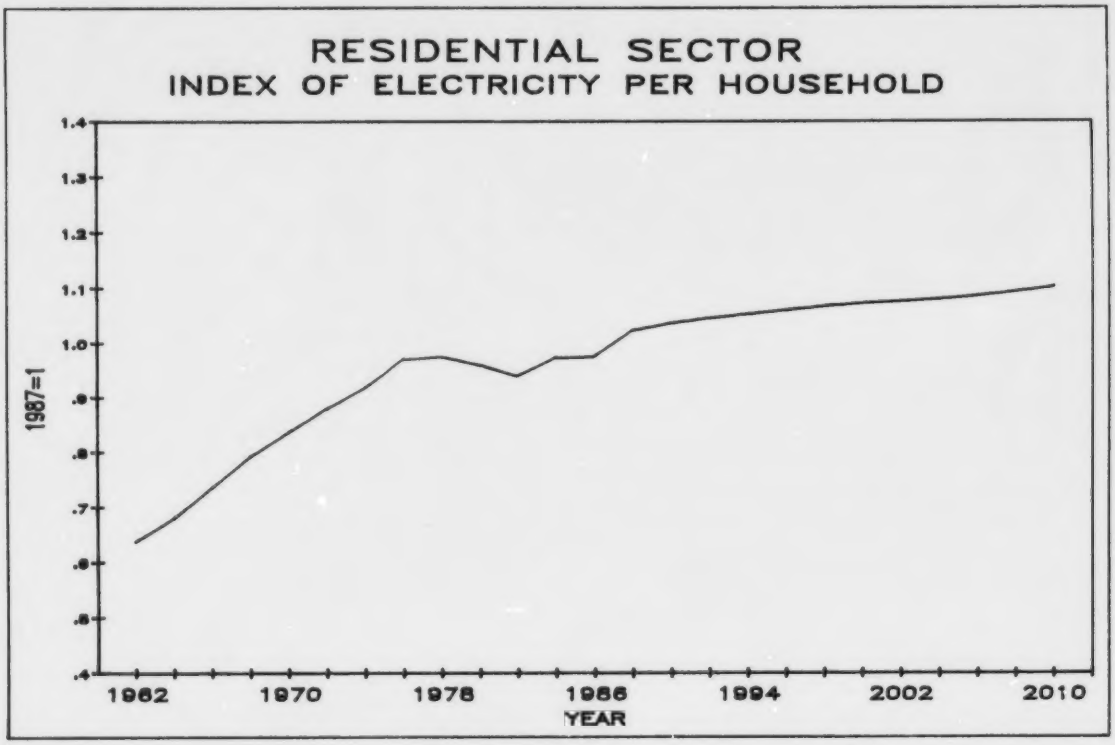


Figure 4.2.1.2

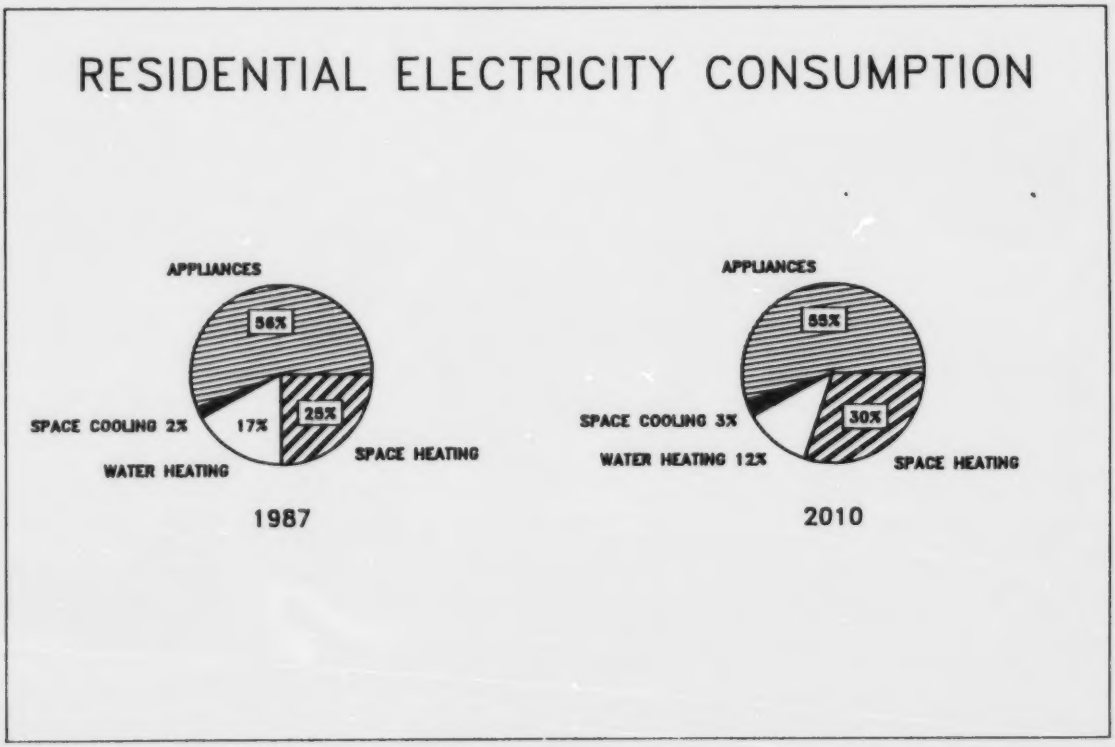


Table 4.2.1.2: Total Stock Forecast
(000's)

Year	Single Det.	Semi/Duplex	Row	Apartment	Total
1987	1972548	320972	188694	937743	3419954
1990	2134974	326484	212926	998567	3672951
1995	2345981	334426	247801	1088588	4016796
2000	2526059	340789	278501	1167011	4312359
2005	2690755	346089	306663	1238922	4582428
2010	2849949	351013	333013	1307146	4841121

End Use Analysis

Over the past 15 years average annual growth in electricity demand in the residential sector has been approximately 3.5% while in the past three years electricity use has grown on average roughly 6% per year. This recent strong growth has been driven by a number of factors: high construction activity, increasing penetration of electric space heating and air conditioning, very strong growth in appliance and auxiliary uses of electricity. Higher household incomes has been a major cause of these acquisitions and usages. This strong growth is expected to continue in the short run and slowly begin to moderate towards the end of the century as construction slows down and further efficiency gains are made.

A good measure of electricity consumption patterns is given by electricity use per household levels obtained by dividing total electricity demand in the residential sector by the total number of households (indexed to 1987=1.0). Reliable data on residential electricity consumption patterns are available from 1962 to 1987 as are the housing stock numbers. These data reveal some distinctly different patterns. See Figure 4.2.1.1. During the 1960's and early 1970's electricity use grew at a rate approximately twice that of housing stock. This growth in electricity intensity came mainly from rapid increases in the penetration of virtually all electricity using devices. The end use stock installed at this time was relatively inefficient. With the energy crisis of the early 1970's, there was a major shift in energy usage patterns. Conservation trends for oil and gas had a spill-over effect on electricity consumption per end use. Coupled with this trend was the fact that many residential appliances began to reach saturation levels. In fact, electricity began to experience increasing competition in areas such as water heating and actually lost market share in some areas.

Most of the trends identified in the recent past are forecast to continue into the future, however the electricity per household ratio will increase slightly as the rate of building slows down faster than demand. The growth in electricity demand stems from four factors: increases in housing stock, increases in intensity of use, increases in penetration rates and increases in market share in areas where electricity competes with other fuels especially in space heating. It is not expected, however, that any of these elements will grow at the same rates that were experienced in the 1960's and early 1970's. The electricity growth rate will be moderated by increases in the efficiency with which a given quality of service can be provided. The following discussion summarizes the major trends determining electricity demand growth in the principal end uses in the residential sector.

Space Heating: Approximately 30% of all electricity use in the residential sector is for space heating. Market share is the most critical determinant of the electric space heating forecast. Presently there are about 380,000 all electric houses in the province. This represents about 15% of all single-family houses. Oil (21%) and natural gas (63%) make up the bulk of the remaining space heating market. By 2010, it is expected that there will be approximately 825,000 all-electric houses (not including apartments) equivalent to 23% of the total stock. Natural gas will remain the dominant space heating fuel with a share of approximately 67%. By itself, this increase in share of electricity for space heating would lead to an average annual rate of growth for electricity of about 3.4%. However, when changes in electricity use per unit (efficiency gains) are factored in, electricity used for space heating grows at roughly 3.1% per annum.

For apartments, it is expected that electric space heating will have an even higher penetration rate. The current stock average level is approximately 20%, with new buildings having 40% electricity share. By 2010, the stock average will be roughly 45% with marginal buildings having more than 70% share. Heat pumps will make up a substantial amount of this share, especially in the rapidly growing condominium market.

As stated, the difference in the growth rate between market share and electricity for heating can be attributed to efficiency gains and conservation efforts. Note, however, that the overall decrease in the use per unit is not anticipated to be very large. In fact, electricity use per house for space heating experiences only a moderate improvement from the present level of approximately 18,000 KWh per year to 16,900 KWh per year by 2010. This is because efficiency improvements for electric space heating are moderated by a number of other effects. Firstly, average house size is on the increase. Recently available information suggests that the average size of a new house has increased by about 500 square feet over the past 15 years. A trend in increasing house size is also expected in the future. With larger houses comes the need for more heating. Secondly, Table 4.2.1.2 indicates the continued strong growth of single detached houses. Ontario Hydro surveys suggest that the average consumer will continue to prefer single detached houses to the other housing types. Thus space heating demand per house will continue to be higher than if there were more row or semi-detached structures. Finally, although efficiency improvements will continue to be made, electrically heated homes tend to be newer and already incorporate large improvements in building envelope and design. Thus any further improvements will be more expensive and complicated and the willingness of the homeowner to undertake such improvements is diminished.

Air Conditioning: The air conditioning end use, although small in the residential sector, is experiencing fairly rapid growth. At present, Ontario Hydro predicts that air conditioning demand will double over the next 15 to 20 years. This represents a growth rate of over 5% per year. The growth may be attributed to an increase in the penetration rate for air conditioning from the present level of approximately 13% to roughly 28% by the year 2010. This relatively rapid growth rate is not unreasonable in light of the large number of room and central space-cooling units currently being installed in both new and old houses. In fact, the past three years have seen record sales of room air conditioners in spite of their low efficiency level. It could be argued, therefore, that an even stronger growth in air conditioning is warranted. However, it appears that this exceptionally strong growth during the last three years is atypical and was strongly influenced by unusually hot weather which is

not considered to represent normal future weather patterns. In fact, a portion of these record sales can be considered as advanced sales.

Appliances: The Ontario Hydro forecast has electricity for appliance usage growing at approximately 2.1% per year, a growth rate which is 0.6% per year higher than that of our housing stock forecast. The implied increase in appliance electricity use per house is driven by ongoing increases in the penetration rates for electric appliances (ie. more dishwashers, clothes dryers, microwaves, second refrigerators etc.) due to higher incomes, and the emphasis on single detached houses in our forecast (which tend to purchase more and bigger appliances). These positive factors are offset in part by efficiency gains as new equipment slowly penetrates the market. The net gain due to efficiency improvement is reduced by the increase in the quality of service consumers will demand (eg. larger refrigerators, more options etc.). The following tables show average electricity demand per appliance and total usage by appliance for 1987 and 2010. These figures include expected efficiency improvements and do not take into account the potential imposition of appliance efficiency standards.

Table 4.2.1.3: Average Electricity use per Appliance
KWh per Appliance per year

	1987	2010
Stoves	1000	830
Refrigerators	1250	1070
Freezers	900	780
Dishwashers	250	230
Clothes Washers	100	95
Clothes Dryers	1000	940
TVs/Radios	600	535
Lighting	100	85

Note that for a given appliance the same usage level (hours per year) was assumed throughout the forecast period.

Table 4.2.1.4: Total Electricity Use by Appliance Type (TWh)

	1987	2010
Stoves	3.5	4.9
Refrigerators	4.0	5.2
Freezers	1.9	3.1
Dishwashers	0.3	0.7
Clothes Washers	0.2	0.3
Clothes Dryers	2.0	3.3
TVs/Radios	1.8	2.6
Lighting	2.4	3.0

Water Heating: In 1987, roughly 18% of all residential electricity use was for water heating. However, the importance of the electric water heating market for Ontario Hydro is on the decline as the number of houses with oil space heating and electric water heating decreases. By the year 2010, it is expected that water heating will account for only 12% of electricity use in the residential sector. This represents a market share of approximately 32%, down sharply from the present level of 40% and the 1980 level of 52%. Natural gas will be

the predominant fuel for water heating, as it is for space heating. Since most homeowners using gas for space heating will use the same fuel for water heating, electric water heating market share will converge to the sum of the electric and oil space heating market shares.

The composition of final demand for electricity in the residential sector by end use is given in Figure 4.2.1.2.

4.2.2 Commercial Sector Forecast

The analysis of energy use in the commercial sector starts with the building stock and its energy consumption patterns. The heterogeneity of the sector demands that each building type's usage and level of floorspace be examined separately. For this year's forecast nine basic building types were examined. These are education (elementary/secondary and colleges/universities), health, offices, retail, warehouses, recreation, religious and cultural, hotels and restaurants and a miscellaneous building category. Non-building related electricity demand for the commercial sector is also examined. Typically these uses include streetlighting, municipal waterworks, construction (for all sectors), etc. This non-building demand has historically accounted for approximately 10% of commercial electricity demand.

The forecasts of floorspace by sub-sector were developed using single-equation econometric models. These models related historical floorspace construction rates to factors such as population, employment and Gross Domestic Product (GDP) at the two-digit level. The forecast of total floorspace for the commercial sector as a whole shows a growth from approximately 1.6 billion square feet in 1987 to roughly 2 billion square feet by the year 2010. This represents a growth rate of approximately 1.1% per year compared to about 1.9% over the last 20 years. About the same number of square feet are added in both periods. The four largest sub-sectors are expected to experience vastly different growth patterns: offices and retail grow at rates above 2% per year, warehouses only moderately and education actually decreases as the demolition rate surpasses the construction rate. Changing demographics and the continuing shift towards a service-based economy are the key factors affecting the floorspace forecast.

The strong growth in electricity use which occurred in 1986 was repeated in 1987 and has continued into 1988. Two main reasons may be cited: high rates of commercial sector activity as measured by employment, Gross Domestic Product and construction; and greater intensity and penetration of electricity usage and electricity using equipment. The latter trend was especially evident in the area of air conditioning with record summer temperatures causing record summer peaks on the entire system and supply constraints in some areas. Note, however, that this demand was related more to high usage levels than to large changes in the penetration rate.

In 1987, commercial sector GDP grew about 4.1%. Most dynamic were the finance, insurance, real estate and banking sectors. The retail and trade sectors also experienced high levels of growth. These economic sectors may be readily associated with the office and retail building types. The high levels of economic activity spurred record construction for these two building categories. Furthermore, since electricity use and GDP are strongly correlated, these two categories recorded strong growth in electricity demand- -4.6% for offices and 5.1% for retail. The floorspace growth rates for these two sub-sectors were 3.7% for offices and 5.5% for retail.

By the year 2010, it is expected that the commercial sector will consume approximately 59.5 TW.h of electricity, up from a 1987 level of 35.8 TW.h. This represents a growth rate of approximately 2.2% per annum. For building-related electricity demand the growth rate will be roughly 2.4% per annum. Note that this growth rate is considerably higher than that of floorspace (1.1%). This implies a forecast trend towards increasing electrical intensity per square foot of floor area averaged across the sector as a whole. Historically, this trend has been very strong (see Figure 4.2.2.1) and it occurs in the future despite conservation efforts and the technological potential to reduce electricity demand (only efforts that arise from normal market forces are included here).

A large part of the explanation lies in the mix of building types within the commercial sector. Historically, institutional type buildings (schools, hospitals, etc.) dominated commercial sector electricity demand both in terms of the absolute level and the contribution to annual growth. These types of buildings typically had fairly low and stable electricity intensity levels. Since the 1970's however, the office and retail sectors have been the areas of rapid growth, both in construction of new space and in electricity demand. These building types have much higher, and growing, electricity intensities. Analysis conducted this year indicated that these two sectors alone have been responsible for much of the growth in both commercial electricity demand and commercial GDP.

<u>End-Use Analysis</u>

Space Heating: Total energy use over the forecast period is estimated to grow by roughly 1.2% per year. Space heating, the predominant end use, will continue the downward trend in terms of its share of total energy (all fuels) observed in the past several years. The main reason for this is the impact of new more efficient building envelopes and heating system design in buildings coming into service over the forecast period. The space heating share of total energy demand will decrease from its current level of about 56% to just under 50% by 2010. As well, electricity will continue to play a larger role in space heating. In fact, it is predicted that electricity's share of the space heating market will rise to about 23% for the entire commercial sector with some sub-sectors having levels even higher. Currently the level is about 9%. Heat pumps, with their high levels of efficiency, will account for a large part of this increase in electricity's share of the space heating market. Note that heat pumps will be a preferred method of heating due to their dual heating/-cooling capability.

Air Conditioning: Air conditioning will account for a much larger portion of the total electricity demand. Although air conditioning systems will become increasingly more efficient, they will be installed in more and more buildings. For example, it is expected that for new buildings the average penetration rate for air conditioning will be over 50%. Offices, health care, retail and accommodation buildings will have penetration rates close to 100% while even buildings such as schools and cultural institutions will contribute to more air conditioning demand.

Lighting: The single largest use of electricity in the commercial sector is lighting. At present, it accounts for about 40% of the total electricity use in this sector. By the year 2010, however, its contribution will be about 30% (15.4 TW.h). Although a number of energy saving options are technically feasible for the future, only the savings associated with the penetration of

Figure 4.2.2.1

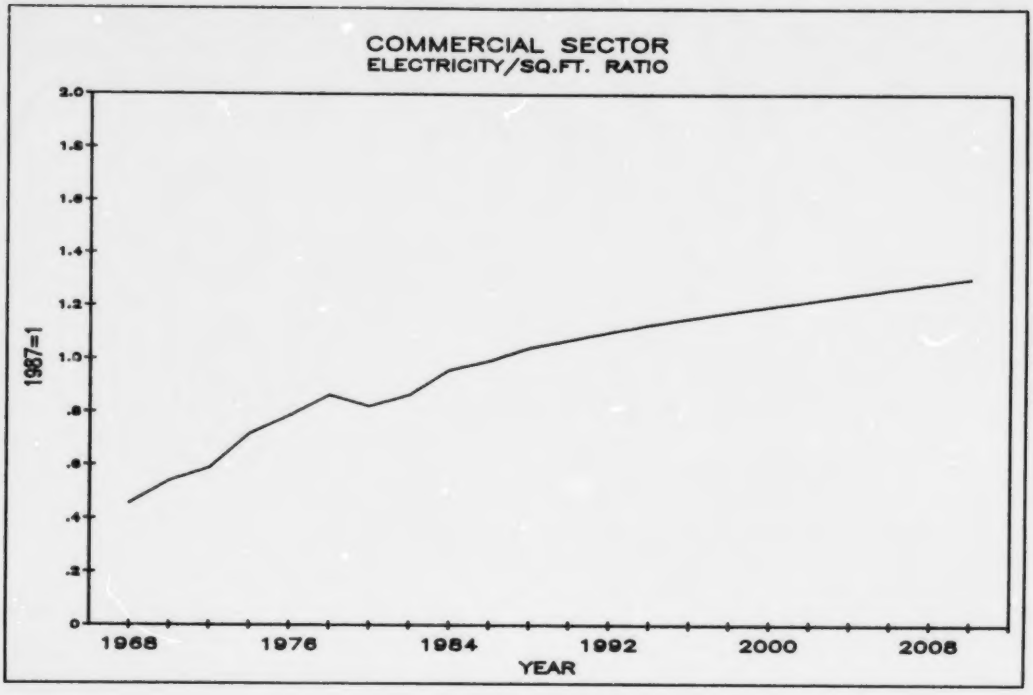
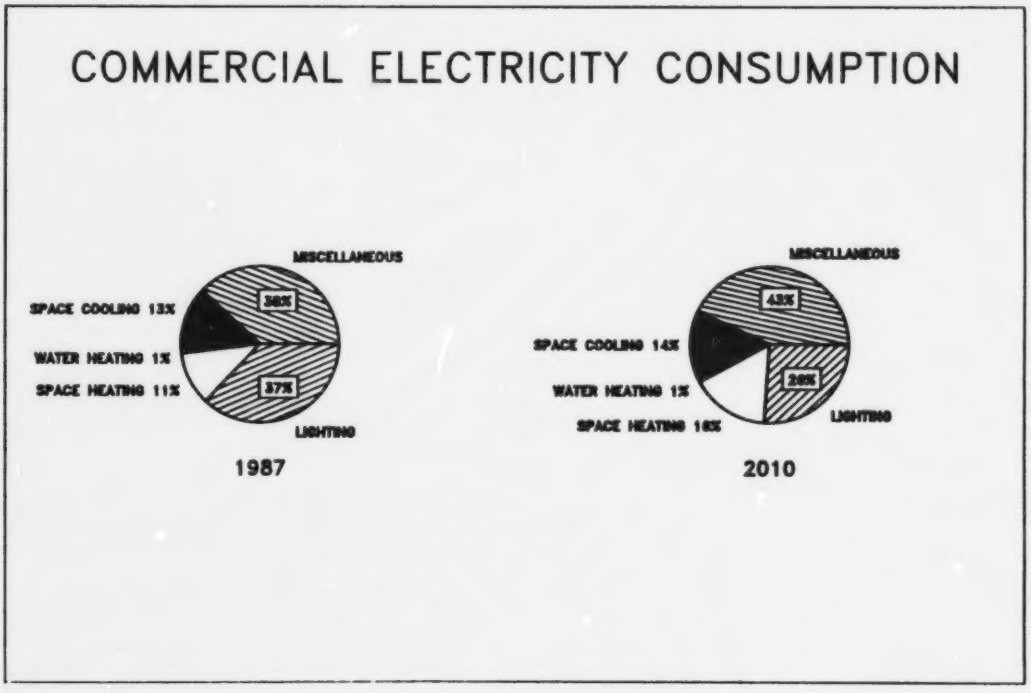


Figure 4.2.2.2



34W fluorescent bulbs are included in the Basic forecast. The average stock efficiency in the year 2010 is assumed to be 10% greater than the average efficiency of the stock currently in use. Any growth in commercial sector electricity demand due to lighting will be caused purely by increases in the floor stock.

Miscellaneous: An area of rapid growth in terms of electricity use in the commercial sector is "miscellaneous" uses. These include office machines, personal computers, ventilation systems, refrigeration, etc. Of these, ventilation and office equipment (including personal computers) are having a tremendous effect on electricity demand, both peak and total energy. A recent study conducted by the Load Forecasts Department indicated that personal computers and the like are accounting for up to 50% of electricity demand in a typical large office building. Of this demand, only about a third is considered to be the direct load of the equipment. The remaining two-thirds is indirect load such as additional space cooling and lighting induced by its operation. For offices, retail and health it is expected that the intensity of use of miscellaneous equipment will increase by about 65% over the forecast period. With limited electricity efficiency improvements in much of this equipment, the implication for the electricity forecast is that miscellaneous equipment electricity demand will increase by more than 2.5% per year and will represent over 40% of all commercial sector electricity demand by 2010.

As stated, included in commercial sector electricity demand are a number of uses which are not building related. Little attempt was made to explain their growth in previous forecasts. This year, a single-equation econometric model was developed to forecast streetlighting directly. This model also explicitly accounted for the mix of different efficiency levels in streetlighting technology. The remainder of this sub-sector is now tied to the forecast of growth in the housing stock. The resulting forecast for growth of non-building related electricity demand is roughly 1.5% per year, with streetlighting growing at about 0.5% per year.

The composition of final demand for electricity in the commercial sector by end use is given in Figure 4.2.2.2.

4.2.3 Industrial Sector

The industrial sector forecast covers the resource, construction and manufacturing (minus petroleum refining) sectors. The existing end-use model (EUM) deals individually with 13 major energy-using industries defined at the two- or three-digit SIC level. The remainder is covered under a sector known as "other industry".

Each individual industry is defined in terms of a number of processes. The iron and steel industry, for example, is defined in terms of pig iron production, raw steel production and finishing operations. Different technologies may be available to perform a given process. Both basic oxygen and electric arc furnaces may be used to produce raw steel, for example.

The individual industry energy demand forecasts are built up by first determining the market share and fuel intensity of each technology within a process. The activity level of each process is then derived from production forecasts of the major goods produced by each industry. These production forecasts are produced exogenously using single equation econometric models. An energy demand forecast for each industry is finally produced after summing over the energy consumption of each technology and process.

In order to remain competitive, industry is driven by a need to minimize costs while continuing to improve product quality. The implications for electricity demand of these twin desires are not immediately obvious. In certain industries, especially those with electricity-intensive production processes, concerted efforts have been made to reduce electricity demand per unit output with some success. New membrane cell chlor-alkali plants for chlorine production use substantially less electricity than older diaphragm cell plants, for example. In other industries, however, efforts to reduce costs and/or improve product quality have led to increased electricity use per unit output. A number of examples are cited in the following section. End-use models provide a consistent framework to evaluate the impact of these changes on total electricity demand.

A common index of intensity is electricity use divided by real Ontario industrial GDP. As seen in Figure 4.2.3.1, this ratio has been on a generally downward trend over the period 1962-1987 except for an abrupt increase during the recession years of the early 1980s. This increase resulted from a large decrease in industrial output which was not matched to the same extent by a decrease in electricity demand. In other words, some of the industries whose output suffered greatly during the recession were not particularly large contributors to electricity demand. This increase did not result from significant technological innovation which increased electricity demand.

Based on the results of the end-use model, this index is expected to remain relatively constant to the late 1990s, declining somewhat by 2010.

Industry Analysis

This section summarizes the electricity demand forecasts for the eight major electricity using industries. Figure 4.2.3.2 shows the forecasts for six of these. The 'other' industry grouping contains the remainder of the sector's industries.

Automobile Manufacturing

Automobile production is expected to increase at an average annual rate of 2.6% to the year 2000, slowing to 1.7% for the ten year period following. Electricity demand is expected to grow somewhat faster over the same two periods at 2.8% and 2.1% respectively, due to increased automation and use of electric heat treatment equipment. Efficiency improvements in lighting and motive power applications are expected to mitigate the effect of these technologies.

Food and Beverage

Production growth is forecast at 2.1% per annum to the year 2000 and 1.2% for the period 2000 - 2010. The adoption of such electrotechnologies as microwave heating, freeze concentration, heat pumps and membrane separation will increase electricity demand at the expense of fossil fuels. The effect of these electrotechnologies in combination with more efficient refrigeration units and greater penetration of adjustable speed drives is expected to result in electricity demand growth of 2.4% over the 1987-2000 period and 1.3% over the 2000-2010 period.

Figure 4.2.3.1

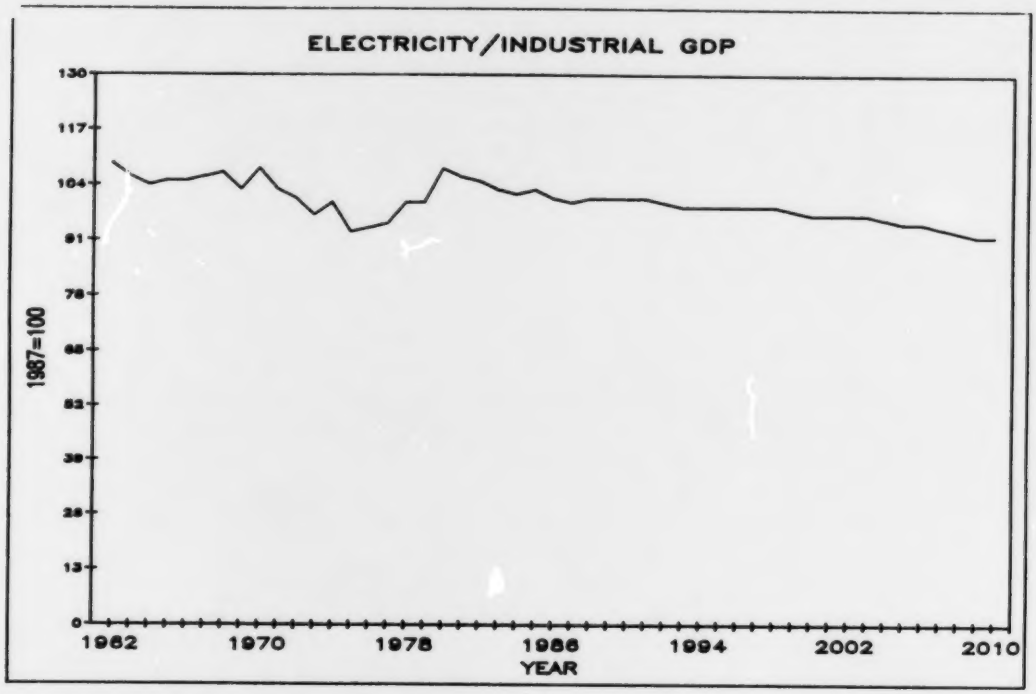
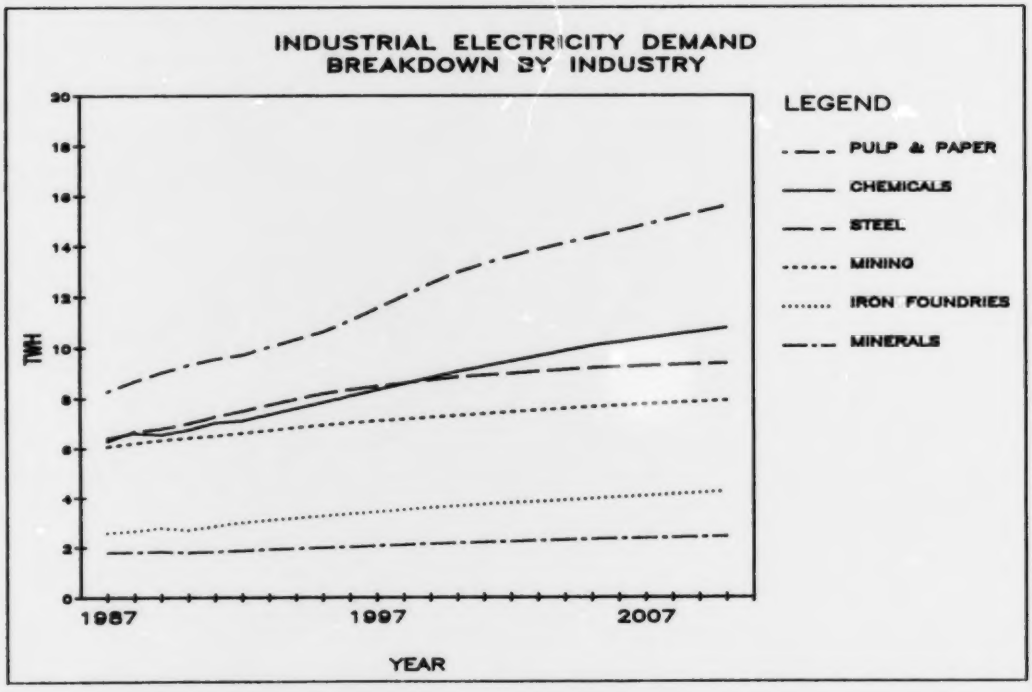


Figure 4.2.3.2



Industrial Chemicals

Production growth to 2010 in the industrial chemicals industry is forecast at 1.4% per annum for chlorine, 2.0% for ammonia, 4.5% for ethylene and 2.8% for other chemicals. It is expected that all new chlorine production capacity will use membrane cell technology which is approximately 20% more electricity efficient than the diaphragm cell technology currently in use. Continuing research and development will likely improve membrane cells' electricity efficiency a further 10% by the year 2010. It is expected that other electricity-intensive chemicals such as sodium chlorate, calcium carbide, oxygen and nitrogen will also improve in efficiency. New ammonia production capacity is expected to be similar in design to the extremely energy efficient CIL-II plant completed in 1985. Other new petrochemical capacity, including ethylene, is assumed to be slightly more electricity-intensive than existing capacity given the expectation that steam turbines will be replaced to some extent by electric motors. The resultant electricity growth for the industrial chemicals industry as a whole is 2.7% for 1987-2000 and 1.7% for 2000-2010.

Iron Foundries

Iron castings production is forecast to increase at a rate of 3.2% per year from 1987-2000 and 1.8% from 2000-2010. Electric melting furnaces offer improved product quality and productivity and fewer environmental problems than traditional cupola furnaces. As a result, they are expected to increase their share of the market over the forecast period. The resulting increase in electricity demand is moderated by the improved efficiency of new furnaces and utility operations. Taking all these factors into account results in electricity demand growth of 2.8% to 2000 and 2.2% from 2000-2010.

Iron & Steel

Demand for raw steel is expected to grow by 1.3% per year from 1987-2000, slowing to only .3% per year from 2000-2010. Given the capital cost advantage of electric steelmaking in comparison to conventional steelmaking, future increases in demand for steel products are expected to be met primarily by expansion of electric steelmaking capacity. This should result in electric arc furnaces increasing their share of production from the present 15% to 25% by 2010.

Measures to improve the quality and competitiveness of steel (e.g. ladle refining furnaces) and a shift toward more cold rolled and specialty steel are expected to increase the electricity required per unit of raw steel. Improved electric arc furnaces, adjustable speed drives on pumps and fans and rolling mill digital control will have the opposite effect. The overall effect of these measures is expected to be a 20% increase in electricity requirements per unit of steel production. As a result, electricity demand is forecast to grow at 2.7% from 1987-2000 and at .6% from 2000-2010.

Mining, Milling, Smelting and Refining

Production growth in the mining sector is forecast to be relatively slow at 1.2% per year for nickel, .9% for copper, .8% for zinc and .8% for other minerals over the period 1987-2000 and .6%, -.7%, .5% and .6%, respectively over the period 2000-2010. In the mining operation, the trend toward all-electric mines is expected to continue. Counterbalancing this growth will be electricity savings due to adjustable speed drives for pumps and ventilation

fans. In the nickel smelting operation, it is expected that reverbatory smelting will be replaced by the more electricity-intensive flash smelting. No major changes in the electricity requirements of the other operations is foreseen. The overall result is average growth of 1.5% from 1987-2000 and .8% from 2000-2010.

Non-Metallic Minerals

The non-metallic minerals industry is composed of the abrasives, cement, clay, glass and lime industries, each of which is modelled separately in the EUM. Production growth rates from 1987 to 2010 range from .9% for silicon carbide in the abrasives industry to 2.3% for glass products. In general, no changes are foreseen which would have a major impact on the electricity intensiveness of these industries. Technologies expected to increase demand include electric boosters in glass melting furnaces and preheaters and precalciners in cement production. Technologies expected to decrease demand include more efficient electric furnaces in the abrasives industry and high efficiency separators in the cement industry. Overall, electricity demand growth is forecast at 1.5% from 1987 to 2000 and 1.1% from 2000 to 2010.

Pulp and Paper

Expected growth rates for pulp and paper products to 2010 are .6% for newsprint, 3.6% for fine paper, 1.4% for export pulp and 2.6% for other paper products. Thermo-mechanical pulp (TMP), which is 25-50% more electricity intensive than other pulps currently produced, is expected to increase its share in newsprint production from 14% to 40% by 1995 and to 100% by 2010. In fine paper, TMP is expected to reach 30% by 2010 from 0% at present. The composition of export pulp and other papers is not expected to change significantly. Electrotechnologies expected to increase electricity demand in papermaking include calcoil calendering, infrared drying and multi-ply forming for boxboard production. Adjustable speed drives are considered likely for all new papermaking machines. Digital control systems for both pulping and papermaking processes are also expected to decrease electricity demand. The overall result is that electricity demand is expected to grow by 3.5% to 2000 and by 1.9% from 2000 to 2010.

Other Industries

Industries of note include rubber and plastic products (3.9% growth in electricity demand to 2010), electrical and electronic products (3.8%), metal fabrication (3.4%) and chemical products (3.4%). These growth rates are a result of relatively healthy production growth forecasts combined with an expected slight increase in electricity intensiveness. Slower growth is expected in textiles and clothing (1.8% growth in electricity demand to 2010) and agriculture (1.2%).

Other Fuels

Other major energy forms in the industrial sector are natural gas (including natural gas liquids), refined petroleum products, coal (including coke and coke oven gas) and hog fuel (wood and spent pulping liquor). In general, natural gas is assumed to be the fuel of choice for most new fossil-fuel fired industrial processes leading to a growth rate of 1.6% over the forecast period. Refined petroleum products, at 1.0% growth to 2010, are expected to hold on to a portion of their market given the relatively low price increases foreseen for

them in the future and the unavailability of natural gas in certain areas. The use of coal, coke and coke oven gas is closely tied to the fortunes of conventional steelmaking. Given the low growth of the iron and steel industry and the increased penetration of electric arc furnaces, a growth rate of .7% to 2010 is forecast. Hog fuel use in the pulp and paper industry is expected to grow at 1.6% per annum as companies seek to reduce their purchased energy costs. In terms of market share, electricity is expected to go from 19.7% to 23.8% from 1987 to 2010, natural gas from 37.9% to 39.4% and hog fuel from 8.4% to 8.7%. The shares of refined petroleum products and coal are both expected to decline, going from 12.0% to 9.8% and 22.0% to 18.4%, respectively.

4.2.4 Transportation Sector

The transportation sector, although a large consumer of energy, accounts for only a small percentage of total electricity demand. Electricity use in transportation is composed almost entirely of the energy requirements of subways, streetcars and trolley buses. Given the expectation of increased ridership and the possibility of expansion of the subway and streetcar systems, growth in electricity demand is expected to occur at a slow to moderate pace over the 1987 - 2010 period. Neither railway electrification nor the large-scale introduction of electric automobiles is foreseen during this period.

The demand for other fuels in the sector is expected to increase at a moderate pace, driven by growth of the population and the economy. Given the outlook for relatively slow growth of real fossil fuel prices, vehicle efficiency improvements are unlikely to be large.

4.2.5 The 1988 End-Use Forecast

The final demand for electricity by sector is given below. The "Primary" category refers to pipeline and refinery demand. The "Adjustment Factor" incorporates load displacement and transmission and distribution losses. In addition, any other factors required to bridge the gap between the end-use model results (total Ontario electricity demand) and the Basic Energy Demand forecast (electricity supplied by Ontario Hydro to Ontario customers) are included in this factor.

Table 4.2.5.: End-Use Forecast (TW.h)

Year	Residential	Commercial	Industrial	Transportation	Primary	Total
1987 (A)	39.2	35.8	46.2	0.4	2.0	123.6
1988	41.1	38.1	48.0	0.4	2.1	129.6
1990	43.7	40.6	50.0	0.4	2.2	136.9
1995	49.3	45.9	57.8	0.4	2.5	155.8
2000	54.5	50.6	66.0	0.4	2.8	174.3
2005	58.8	55.1	72.3	0.5	3.0	189.7
2010	63.2	59.5	78.0	0.5	3.2	204.5
Growth Rates						
1987-2010	2.1	2.2	2.3			
1987-1995	2.9	3.1	2.8			
1987-2000	2.6	2.7	2.8			
1987-2005	2.3	2.4	2.5			

(A) - Actual

Year	Total	Load* Displacement	Adjustment+	Basic Electricity Demand
1987 (A)	123.6	3.7	6.6	126.5
1988	129.6	3.7	6.7	132.6
1990	136.9	4.1	7.1	139.9
1995	155.8	4.2	8.1	159.7
2000	174.3	4.8	9.1	178.6
2005	189.7	5.2	9.9	194.4
2010	204.5	5.6	10.7	209.6
Growth Rates				
1987-2010				2.2
1987-1995				2.9
1987-2000				2.7
1987-2005				2.4

(A) - Actual

* brought about by normal market forces

\+ Ontario Hydro losses less Ontario electricity not sold by Ontario Hydro (excluding load displacement); statistical differences

All three sectors are forecast to show similar growth, with the industrial sector the strongest at 2.3%. The residential sector's share of the electricity demand market will decrease slightly from a current level of 31.7% to 30.9% by 2010. This share is expected to be picked up by the industrial sector. The commercial sector will maintain a share of 29%.

Over the period 1987 - 2010, the absolute growth in Basic electricity is forecast to be 83.1 TW.h.

5.0 LOAD IMPACT OF INCENTIVE-DRIVEN DEMAND MANAGEMENT AND LOAD DISPLACEMENT

5.1 Introduction

The end-use, econometric and recommended forecasts described earlier in this section are all 'Basic' forecasts of load in Ontario. That is, they are projections of the load that Ontario Hydro would expect to serve as a result of market forces where there are no interventions by Ontario Hydro in the form of incentives. The Primary Load Forecast is derived by subtracting from the 'Basic' the load impact of incentive-driven demand management and load displacement generation.

Ontario Hydro's incentive programs for demand management include both changes in rate structure to achieve load-shifting, such as time-of-use rates, and financial incentives for electrical efficiency improvement to reduce load, such as grants or attractive loans.

Ontario Hydro's incentive programs for load displacement generation provide financial assistance to industries wishing to produce electricity for their own consumption, thereby reducing the load Ontario Hydro is required to serve.

It is the Primary Load Forecast minus interruptible loads and Control Centre Controlled loads which is used by System Planning to derive their Planning Firm Load series.

5.2 Incentive-Driven Demand Management

The load impact estimates for incentive-driven electrical efficiency improvement programs are based on the short-term targets (1989-1993) set by the Energy Management Branch and the results of sector-specific demand management studies undertaken by the Economics and Forecasts Division. An estimate of the impact of time-of-use rates was prepared by Energy Management Branch based on Ontario Hydro's experimental study and other utilities' implementation experience. This was reviewed by the Economics & Forecasts Division and adopted for the forecast as it contains the best information available. Further research is planned to assess the response of the customers facing time-of-use rates. Time-of-use rates account for most of the load-shifting in this forecast. Estimates of the impact of other load shifting programs were provided by Energy Management Branch.

The forecast does not yet have associated with it an uncertainty range. At best, it can be said to contribute to the total uncertainty in the load forecast.

5.2.1 Electrical-Efficiency Improvement Programs

Table 5.2.1 lists, by sector, the incentive-driven electrical efficiency-improvement program areas. In the residential sector, the New Housing Program will offer incentives to buyers of R2000 homes. The Renovation Program will address the retrofit market by offering incentives for a number of technologies, including window replacements, weather stripping/caulking, lighting improvements and envelope upgrades. The Heat Pump Program will address both new and existing housing markets, and will provide incentives toward the installation of ground source heat pumps. The program for the agricultural component of this sector will offer incentives for a wide range of improvements, including energy-efficient lighting, control systems, high-efficiency vents, etc.

Table 5.2.1: Incentive-Driven Efficiency Improvement Program Areas

Residential/Agricultural Sector

1. New Housing
2. Renovation
3. Heat Pumps
4. Agriculture

Commercial Sector

1. Energy-Efficient Lighting
2. Savings by Design
3. Streetlighting Conversion
4. Energy Audits
5. Room Motion Sensors (hospitality sub-sector)

Industrial Sector

1. Energy-Efficient Lighting
2. High-Efficiency Motors
3. Refrigeration (food and beverage sub-sector)
4. Energy Audits and Customized Financial Incentives

Source: 1988 Energy Management Branch, Ontario Hydro.

The programs anticipated for the commercial sector are also listed in Table 5.2.1. The Energy-Efficient Lighting Program will offer incentives for high-efficiency fluorescent lighting, and will be also available to industrial sector customers. The Savings by Design Program will address both the new and renovation markets in the commercial sector, and will offer incentives towards demand reduction measures in construction projects that are customized for each program participant. Eligible technologies include high-efficiency motors and controls, efficient architectural designs, heat pumps, thermal envelope upgrades, control systems, high-efficiency refrigeration, etc. The Streetlighting Conversion Program will aid municipalities in converting to higher-efficiency lamps by offering incentives for these retrofits.

Industrial sector programs will offer incentives for energy-efficient lighting, motors, refrigeration and microwave technologies. Many of the technologies listed above for the commercial sector will also be available through incentive programs to the industrial sector. Additional technologies that will be offered to industrial sector customers include variable speed drives, compressors, fans and pumps, factory automation technologies, DC arc furnaces, new mining technologies, etc.

5.2.2 Load Shifting Programs

The major program in the forecast is the implementation of the time-of-use costing and pricing system which will be phased in over four years effective January 1, 1989. The system will alter the demand/energy split of total revenues and rates will be time-differentiated on both a seasonal and time-of-day basis.

The revenue collected from demand and energy charges will gradually be altered from the current 50/50 split to 42/58 in 1992. The capacity/energy split will remain at 42/58 for a period of ten years.

The rate structure includes four time-of-use periods: winter peak, winter off-peak, summer peak and summer off-peak. Summer is defined as April through September and winter as the remaining months. The peak period in each season is from 7 am to 11 pm Monday to Friday except for public holidays. All other hours are off-peak.

At full implementation demand charges will be 40% higher during the winter than during the summer and will be applied only to peak period demand. Unit energy costs during the peak period will be 25% higher than during the off-peak in the winter and 60% higher than the off-peak in the summer. Average winter unit energy costs will be 25% higher than average summer unit energy costs. These rate differentials will be phased in over the period 1989 to 1992 in line with the changes in the demand/energy split.

The new pricing system will serve all Ontario Hydro direct customers, all large users of municipal utilities, and those municipal utilities which opt for time-of-use billing. Of the 316 municipal utilities and two distributing companies, 88 have opted for billing under time-of-use rates starting in 1989.

5.2.3 The Forecast

Table 5.2.3.1 shows the estimated annual peak load impacts associated with the Demand Management Programs. The year 2000 target of 3000 MW set by the Corporation has been embedded in the forecast.

The peak demand forecast for efficiency-improvement programs incorporates estimates from two sources: (1) short-term (1989-93) targets for incentive-driven efficiency improvement programs provided by the Energy Management Branch; and (2) long-term (post-1993) projections of attainable efficiency-improvement potential produced by the Economics and Forecasts Division.

The latter estimates are based on a number of Economics and Forecasts studies of efficiency improvement potential in the three sectors. The analysis in these studies takes account of existing and new building/equipment stocks by sub-sector and energy end-use, as well as turnover of equipment stocks and assumptions about penetration rates of programs.

The impact of energy-efficiency improvement programs by the year 2000 is distributed by sector as follows: 38 percent residential; 45 percent commercial; and 17 percent industrial. With regard to the 2000-2010 period, the estimates in Table 5.2.3.1 relate only to the efficiency improvement potential of the new (post-2000) building and equipment stocks. In fact, the forecast does not include an additional 750 MW of peak demand savings which could be achieved by 2005 if programs for existing stock continue beyond the year 2000.

In order to translate the peak megawatt savings into an annual terawatt hour per year reduction, the following estimated load factors are used: 34 percent for the residential sector, 75 percent for the commercial sector and 75 percent for the industrial sector. Table 5.2.3.2 shows the annual terawatt hour reductions based on the above load factors.

The forecast of the impact of load shifting programs on system peak demand is based largely on the results of several Ontario Hydro studies investigating time-of-use rates and the implementation experience of other utilities. The impact was allocated on a year-by-year basis based on assumptions regarding the length of adjustment period for various customer classes. The greatest amount of incremental load shifting is expected to occur in the period immediately following the implementation of time-of-use rates.

The forecast reflects the system's maximum load shifting potential of 1000 MW in the year 2000 estimated by System Planning Division. Growth in the total system load is expected to result in the opportunity for additional load shifting beyond the year 2000.

In the case of time-of-use rates it is assumed that the impact is purely one of load shifting and that there will be no increase or reduction in annual TW.h. Research will be required to determine whether customer response in peak periods is exactly offset in off-peak periods. It will take several years at least to assess this for Ontario Hydro's time-of-use rate structure.

Table 5.2.3.1: Load Impacts of Incentive-Driven Demand Management Programs December Peak MW Reduction

Year	Efficiency Improvement Programs		Load-Shifting Programs		Total	
	Per Year	Cumulative	Per Year	Cumulative	Per Year	Cumulative
1989	14	14	80	80	94	94
1990	31	45	89	169	120	214
1991	33	78	94	263	127	341
1992	48	126	158	421	206	547
1993	57	183	159	580	216	763
1994	131	314	75	655	206	969
1995	186	500	60	715	246	1215
1996	300	800	60	775	360	1575
1997	300	1100	60	835	360	1935
1998	300	1400	57	892	357	2292
1999	300	1700	54	946	354	2646
2000	300	2000	54	1000	354	3000
2001	50	2050	35	1035	85	3085
2002	50	2100	30	1065	80	3165
2003	50	2150	25	1090	75	3240
2004	50	2200	25	1115	75	3315
2005	50	2250	25	1140	75	3390
2006	50	2300	25	1165	75	3465
2007	50	2350	25	1190	75	3540
2008	50	2400	25	1215	75	3615
2009	50	2450	25	1240	75	3690
2010	50	2500	25	1265	75	3765

Table 5.2.3.2: Annual TW.h Reduction

Year	Efficiency Improvement Programs	
	Per Year	Cumulative
1989	0.042	0.042
1990	0.133	0.175
1991	0.182	0.357
1992	0.230	0.587
1993	0.292	0.879
1994	0.534	1.413
1995	0.834	2.247
1996	1.214	3.461
1997	1.420	4.881
1998	1.430	6.311
1999	1.430	7.741
2000	1.455	9.196
2001	0.764	9.960
2002	0.256	10.216
2003	0.256	10.472
2004	0.285	10.757
2005	0.227	10.984
2006	0.256	11.240
2007	0.256	11.496
2008	0.288	11.784
2009	0.224	12.008
2010	0.256	12.264

5.2.4 Policy Assumptions Embedded in the Forecast

In generating this forecast, it is assumed that the Corporation will pursue an intensive demand management strategy for the next decade. In particular, a critical assumption is that comprehensive demand management programs with significant financial incentives will be in place during the early 1990s.

In deriving the estimates to the year 2000, the following assumptions were made:

- intensive demand management research will be carried out and completed over the next three to four years;
- programs planned and underway for the 1989-93 period will generate much-needed information and internal expertise;
- expenditures in excess of $2 billion will be made for financial incentives by the year 2000, involving incentives up to the avoided cost of incremental fossil supplies for the Ontario Hydro power system;
- Time-of-use rates will be widely offered to the customers served by Ontario Hydro and Municipal utilities. Where time-of-use rates are not available, other technologies will be used to enhance the opportunities for load shifting.
- the industrial infrastructure (contractors, builders, architects, etc) and institutional environment (eg, municipal electric utilities) will be readied to permit gearing up of full-scale programs;
- any other major financial, information and institutional barriers will be overcome during program design and implementation; and
- given the above considerations, Ontario Hydro will be in a position to launch effective, comprehensive demand management programs by the early 1990s.

5.3 Load Displacement Generation Forecast

Although Ontario Hydro is the dominant supplier of electricity within the province, there are other means by which demand is met. Non-utility generation is a general term encompassing all production of electricity from sources other than those owned and operated by Ontario Hydro. Non-utility generation which is interconnected to the Bulk Electricity or Distribution System is referred to as parallel generation. Generation not normally supplied to the grid (although it is often tied to the grid for back-up or potential sales) is called self-generation. Co-generation is the simultaneous production of electricity and thermal energy from a single fuel source. As can be seen from the above definitions, co-generation is a form of non-utility generation which can contribute to parallel generation.

The end-point of both the End-Use model and the Econometric Energy Model is a forecast of total electricity demand within the province of Ontario, regardless of how it is supplied. Since ultimately it is Ontario Hydro Primary Energy (amount of electricity which Ontario Hydro must generate or purchase to meet demand within Ontario) which is forecasted, an accounting must be made of the

non-utility generation which displaces demand Ontario Hydro would otherwise need to supply. This load displacement generation occurs when customers themselves generate and consume electricity which would have been purchased from Ontario Hydro. A portion of co-generation serves as load displacement generation. The portion of co-generation sold to Ontario Hydro, as well as other parallel generation such as small hydro, is considered to be a supply resource for planning purposes and is not investigated further here.

The forecast of co-generation is the sum of generation from currently existing and new facilities. The Non-Utility Generation Division has forecasted that 1000 MW of new co-generation capacity will be in operation by the year 2000, of which 500 MW is currently under construction, committed or in the planning stage. By 2010, 1900 MW of new co-generation capacity is expected. The major contributors to the 1000 MW total in 2000 are the pulp and paper industry (350 MW) and the industrial chemicals industry (340 MW). Out of a total of 824 MW of co-generation capacity currently existing, 393 MW is owned by the pulp and paper industry and 301 MW by the industrial chemicals industry.

About 60% of the new co-generation capacity is expected to be used for load displacement. The remainder is expected to be sold to Ontario Hydro for use elsewhere. The load displacement percentage varies by industry, from 30% in the food and beverage industry to 100% in mining and primary metals. Approximately 60% of the electricity generated in the pulp and paper and industrial chemicals industries is expected to be used for load displacement. In order to derive the load displacement energy forecast shown in Table 5.3.1 it was assumed that new co-generation capacity will have an 80% capacity utilization factor.

The 1000 MW total discussed above includes generation that would be brought about naturally by normal market forces, as well as that induced by financial incentives. A final calculation is necessary to disaggregate the total load displacement forecast into a "natural" component and an "incentive-driven" component. (The terms "natural" and "incentive-driven" are used in the same sense as for demand management.) The natural component is subtracted out as part of the adjustments from Ontario Electricity Demand to Basic load. Incentive-driven load displacement generation is subtracted from the Basic Load Forecast along with incentive-driven demand management, to derive the Primary Load Forecast. It is estimated that about 20% of the forecasted new load displacement capacity would have occurred naturally. The annual cumulative total of new incentive-driven load displacement generation is given in Table 5.3.2.

Table 5.3.1: Load Displacement Generation

Year	Natural Capacity (MW)	Natural Generation (TW.h)	Incentive-Driven Capacity (MW)	Incentive-Driven Generation (TW.h)	Total Capacity (MW)	Total Generation (TW.h)
1987	824	3.7	-	-	824	3.7
1993	861	4.1	251	1.8	1112	5.9
2000	958	4.8	537	3.8	1495	8.6
2010	1070	5.6	984	6.9	2054	12.5

Table 5.3.2: New Incentive-Driven Load Displacement Generation

Year	Peak (MW)	Energy (GW.h)
1989	20	98
1990	28	194
1991	152	1078
1992	243	1713
1993	251	1759
1994	251	1759
1995	299	2094
1996	346	2430
1997	394	2764
1998	442	3092
1999	489	3535
2000	537	3763
2001	582	4079
2002	627	4394
2003	671	4702
2004	716	5018
2005	761	5333
2006	806	5674
2007	850	5962
2008	895	6267
2009	939	6582
2010	984	6896

TABLE A

COMPARISON OF TOTAL SYSTEM DEMANDS WITH EARLIER FORECASTS

ONTARIO PRIMARY DEMAND

20-MINUTE WINTER PEAK DEMAND - Megawatts

		FORECAST MADE IN						
Winter	Actual	1982	1983	1984	1985	1986	1987	1988
1981/82	18124							
1982/83	17578	17953						
1983/84	18896	18650	18227					
1984/85	19390	19370	18819	19438				
1985/86	20668	20042	19404	19915	19846			
1986/87	20609	20730	20035	20531	20386	21222		
1987/88	22593	21465	20603	21100	20917	21817	22018	
1988/89	23068	22214	21121	21721	21510	22520	22676	23154
1989/90		22987	21636	22198	22116	23065	23245	23688
1990/91		23783	22018	22895	22683	23558	23898	24166
1991/92		24577	22409	23523	23312	23995	24359	24871
1992/93		25385	22851	24116	24029	24364	24892	25468
1993/94		26172	23352	24689	24775	24788	25441	25916
1994/95		26979	23927	25233	25545	25279	25936	26324
1995/96		27760	24545	25859	26029	25766	26291	26423
1996/97		28475	25161	26524	26660	26264	26785	26683
1997/98		29127	25796	27171	27277	26734	27288	26984

ANNUAL ENERGY DEMAND - Terawatt hours

		FORECAST MADE IN						
Year	Actual	1982	1983	1984	1985	1986	1987	1988
1981	101.7							
1982	100.8	104.8						
1983	106.1	108.1	103.3					
1984	112.3	112.5	109.0	111.3				
1985	116.0	116.3	112.6	114.5	115.1			
1986	120.6	120.1	116.3	117.2	117.7	121.0		
1987	126.5	124.4	119.9	120.7	121.1	125.0	125.2	
1988	134.4	129.0	123.5	124.0	124.4	129.0	129.7	133.1
1989		133.2	126.2	127.0	127.4	132.1	133.2	136.9
1990		137.8	129.3	129.8	130.9	135.0	137.0	140.2
1991		142.4	131.6	133.9	134.2	137.9	140.5	143.6
1992		147.9	134.3	137.5	138.0	142.3	144.3	148.3
1993		152.1	136.6	141.0	142.2	145.5	147.9	152.3
1994		156.8	139.6	144.4	146.6	148.8	151.9	155.4
1995		161.4	143.0	147.5	151.2	152.3	155.5	158.2
1996		165.6	146.7	151.2	154.1	155.7	158.0	159.2
1997		169.4	150.4	155.1	157.8	159.0	161.3	161.7

TABLE A1

COMPARISON OF 20-MINUTE WINTER PEAK DEMANDS WITH EARLIER FORECASTS

EAST SYSTEM - ONTARIO PRIMARY DEMAND
Megawatts

Winter	Actual	FORECAST MADE IN						
		1982	1983	1984	1985	1986	1987	1988
1981/82	17335							
1982/83	16793	17103						
1983/84	18009	17756	17404					
1984/85	18525	18412	17975	18553				
1985/86	19711	19056	18537	18989	18905			
1986/87	19679	19722	19112	19572	19445	20261		
1987/88	21615	20423	19661	20127	19953	20834	21020	
1988/89	22081	21133	20155	20738	20506	21518	21675	22123
1989/90		21868	20646	21194	21096	22027	22215	22664
1990/91		22623	21011	21860	21637	22488	22867	23140
1991/92		23370	21384	22459	22237	22930	23324	23811
1992/93		24138	21806	23025	22921	23279	23833	24396
1993/94		24886	22284	23572	23632	23682	24356	24822
1994/95		25653	22833	24091	24367	24150	24829	25245
1995/96		26395	23422	24689	24829	24610	25166	25342
1996/97		27075	24010	25324	25430	25072	25638	25621
1997/98		27695	24616	25942	26019	25520	26120	25919

WEST SYSTEM - ONTARIO PRIMARY DEMAND
Megawatts

Winter	Actual	FORECAST MADE IN						
		1982	1983	1984	1985	1986	1987	1988
1981/82	878							
1982/83	870	895						
1983/84	932	943	900					
1984/85	961	1002	922	955				
1985/86	1012	1032	948	998	995			
1986/87	1015	1056	1008	1033	995	977		
1987/88	1035	1092	1030	1048	1019	1020	1044	
1988/89	1043	1133	1056	1060	1062	1049	1049	1076
1989/90		1172	1082	1083	1078	1075	1084	1070
1990/91		1215	1101	1117	1106	1125	1085	1074
1991/92		1260	1120	1148	1136	1152	1092	1109
1992/93		1301	1142	1177	1171	1153	1111	1123
1993/94		1341	1167	1205	1208	1174	1138	1167
1994/95		1382	1196	1232	1245	1198	1163	1186
1995/96		1422	1227	1262	1269	1226	1187	1174
1996/97		1458	1258	1295	1300	1251	1205	1152
1997/98		1492	1290	1326	1330	1278	1230	1162

TABLE B

COMPARISON OF 1988 AND 1987 FORECASTS

Average Monthly 1-Hour Peak - Megawatts

	Regional Estimates	Unallocated Load	Sum of Customer Loads	IDDM and LD*	Net Diversity & Loss	Primary Demand
1988 Forecast (881212)						
1988	19898	144	20042	0**	-400	19642
1989	20799	-103	20696	-70	-387	20239
1990	21548	-267	21281	-185	-429	20667
1991	22402	-364	22038	-430	-501	21107
1992	23262	-432	22830	-687	-520	21623
1987 Forecast (871214)						
1988	19599	-58	19541	-1***	-374	19166
1989	20363	-215	20148	-46	-385	19717
1990	21078	-341	20737	-131	-397	20209
1991	21811	-463	21348	-220	-461	20667
1992	22492	-575	21917	-363	-486	21068
Difference between Forecasts (1988 Forecast - 1987 Forecast)						
1988	299	202	501	1	-26	476
1989	436	112	548	-24	-2	522
1990	470	74	544	-54	-32	458
1991	591	99	690	-210	-40	440
1992	770	143	913	-324	-34	555

* IDDM and LD = Incentive-Driven Demand Management and Load Displacement

** Includes Load Shifting, Efficiency Improvement Programs and Load Displacement

*** Includes Load Shifting and Efficiency Improvement Programs, but no Load Displacement

TABLE C

LOAD FORECAST REPORT NO. 871214
ONTARIO PRIMARY DEMANDS - TOTAL SYSTEMS

Year	20 Min Annual Peak MW	Annual Energy MW.h	Annual Energy Avg MW	Load Factor
1946	2,036.1	10,575,379.3	1,207.2	59.3
1947	2,262.2	12,495,821.2	1,426.5	63.1
1948	2,393.0	12,991,064.4	1,478.9	61.8
1949	2,443.7	13,511,035.9	1,542.4	63.1
1950	2,753.1	15,175,583.7	1,732.4	62.9
1951	3,063.1	17,241,303.9	1,968.1	64.3
1952	3,247.7	18,401,371.7	2,094.8	64.5
1953	3,442.8	19,590,139.1	2,236.3	65.0
1954	3,655.7	20,471,343.9	2,336.8	63.9
1955	4,183.2	22,877,271.2	2,611.4	62.4
1956	4,468.5	25,135,134.1	2,861.4	64.0
1957	4,737.6	27,002,762.0	3,082.4	65.1
1958	5,093.1	27,979,394.9	3,193.8	62.7
1959	5,510.6	31,143,172.8	3,555.0	64.5
1960	5,699.8	32,319,968.2	3,679.4	64.6
1961	5,902.9	33,569,282.4	3,831.9	64.9
1962	6,247.0	35,488,962.2	4,051.1	64.9
1963	6,750.6	37,288,964.1	4,256.5	63.1
1964	7,163.9	40,305,468.3	4,588.5	64.1
1965	7,818.4	43,511,759.8	4,967.1	63.5
1966	8,565.6	48,054,384.4	5,485.7	64.0
1967	8,963.8	51,355,505.0	5,862.5	65.4
1968	9,994.4	55,788,374.7	6,351.1	63.5
1969	10,555.4	59,424,443.4	6,783.6	64.3
1970	11,288.7	64,287,605.7	7,338.8	65.0
1971	11,534.5	68,132,582.0	7,777.7	67.4
1972	12,738.8	73,495,941.4	8,367.2	65.7
1973	13,605.4	78,162,478.1	8,922.6	65.6
1974	13,538.1	82,695,005.7	9,440.1	69.7
1975	14,512.5	84,220,853.4	9,614.2	66.2
1976	15,895.3	90,851,705.2	10,343.0	65.1
1977	15,901.1	92,853,681.9	10,599.7	66.7
1978	16,246.7	95,371,714.5	10,887.2	67.0
1979	16,364.7	98,126,082.3	11,201.6	68.4
1980	16,807.8	100,172,734.9	11,404.0	67.8
1981	17,189.0	101,658,168.0	11,604.8	67.5
1982	18,123.6	100,835,597.9	11,510.9	63.5
1983	18,791.5	106,071,164.8	12,108.6	64.4
1984	18,896.0	112,293,482.0	12,783.8	67.6
1985	20,473.0	116,048,994.0	13,247.6	64.7
1986	20,668.0	120,573,918.0	13,764.1	66.6
1987	20,524.0	126,455,099.0	14,435.5	70.3
1988	23,012.0	134,394,697.0	15,299.9	66.5
LOAD FORECAST ESTIMATE 881212				
1988	22,690.0	133,052,100.0	15,147.1	66.8
1989	23,276.0	136,926,800.0	15,630.9	67.2
1990	23,748.0	140,172,800.0	16,001.5	67.4
1991	24,426.0	143,633,700.0	16,396.5	67.1
1992	24,978.0	148,330,800.0	16,886.5	67.6
1993	25,612.0	152,291,700.0	17,384.9	67.9
1994	26,040.0	155,446,500.0	17,745.0	68.1
1995	26,423.0	158,183,100.0	18,057.4	68.3
1996	26,454.0	159,178,900.0	18,171.1	68.7
1997	26,778.0	161,685,600.0	18,457.3	68.9

LONG-TERM FORECAST

JAN 19/89

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1988													
20 MIN PEAK MW	22564.	21568.	21082.	18881.	17619.	18173.	18453.	18874.	17778.	18712.	21108.	22690.	19792.0
1 HOUR PEAK MW	22338.	21436.	20908.	18735.	17488.	18063.	18350.	18771.	17635.	18517.	20920.	22545.	19642.1
ENERGY GWH	13023.	11904.	11969.	10380.	10319.	9930.	10272.	10532.	9878.	10704.	11539.	12602.	133052.1
ENERGY AV MW	17504.	17103.	16088.	14417.	13869.	13792.	13806.	14156.	13720.	14387.	16027.	16938.	15147.1
*L.F. %	78.4	79.8	76.9	77.0	79.3	76.4	75.2	75.4	77.8	77.7	76.6	75.1	77.1
1989													
20 MIN PEAK MW	23154.	22203.	21773.	19498.	18178.	18758.	19202.	19467.	18302.	19194.	21692.	23276.	20391.4
1 HOUR PEAK MW	22924.	22069.	21593.	19349.	18045.	18646.	19097.	19363.	18157.	18994.	21500.	23128.	20238.7
ENERGY GWH	13363.	11836.	12365.	10742.	10677.	10276.	10703.	10897.	10210.	11005.	11892.	12962.	136926.8
ENERGY AV MW	17962.	17614.	16619.	14919.	14351.	14272.	14385.	14646.	14180.	14791.	16517.	17422.	15630.9
*L.F. %	78.4	79.8	77.0	77.1	79.5	76.5	75.3	75.6	78.1	77.9	76.8	75.3	77.2
1990													
20 MIN PEAK MW	23688.	22707.	22261.	19891.	18557.	19139.	19606.	20005.	18639.	19541.	22101.	23748.	20823.4
1 HOUR PEAK MW	23450.	22570.	22076.	19739.	18420.	19025.	19499.	19898.	18491.	19336.	21905.	23597.	20666.9
ENERGY GWH	13712.	12143.	12677.	10997.	10940.	10516.	10960.	11131.	10437.	11245.	12154.	13259.	140172.8
ENERGY AV MW	18430.	18070.	17040.	15273.	14705.	14606.	14731.	14962.	14496.	15115.	16881.	17821.	16001.5
*L.F. %	78.6	80.1	77.2	77.4	79.8	76.8	75.5	75.2	78.4	78.2	77.1	75.5	77.4
1991													
20 MIN PEAK MW	24166.	23159.	22703.	20255.	18893.	19499.	20065.	20295.	19071.	20012.	22677.	24426.	21268.6
1 HOUR PEAK MW	23921.	23017.	22512.	20099.	18752.	19383.	19955.	20185.	18917.	19799.	22474.	24269.	21107.1
ENERGY GWH	14027.	12415.	12963.	11231.	11179.	10739.	11207.	11433.	10712.	11554.	12504.	13671.	143633.7
ENERGY AV MW	18854.	18475.	17424.	15599.	15026.	14915.	15063.	15367.	14878.	15530.	17367.	18376.	16396.5
*L.F. %	78.8	80.3	77.4	77.6	80.1	76.9	75.5	76.1	78.6	78.4	77.3	75.7	77.7
1992													
20 MIN PEAK MW	24871.	23811.	23325.	20768.	19352.	19970.	20547.	20767.	19480.	20433.	23185.	24978.	21790.6
1 HOUR PEAK MW	24616.	23665.	23127.	20606.	19206.	19849.	20433.	20654.	19321.	20212.	22975.	24816.	21623.4
ENERGY GWH	14490.	13269.	13367.	11571.	11513.	11042.	11531.	11761.	11004.	11869.	12852.	14061.	148330.8
ENERGY AV MW	19476.	19064.	17967.	16071.	15475.	15336.	15499.	15808.	15283.	15954.	17850.	18899.	16886.5
*L.F. %	79.1	80.6	77.7	78.0	80.6	77.3	75.9	76.5	79.1	78.9	77.7	76.2	78.1
1993													
20 MIN PEAK MW	25468.	24373.	23871.	21221.	19772.	20413.	21014.	21243.	19913.	20898.	23752.	25612.	22296.4
1 HOUR PEAK MW	25205.	24222.	23667.	21055.	19622.	20289.	20897.	21127.	19750.	20669.	23536.	25445.	22124.2
ENERGY GWH	14924.	13192.	13764.	11907.	11850.	11367.	11875.	12111.	11332.	12228.	13249.	14494.	152291.7
ENERGY AV MW	20059.	19630.	18500.	16537.	15927.	15787.	15961.	16278.	15739.	16435.	18401.	19481.	17384.9
*L.F. %	79.6	81.0	78.2	78.5	81.2	77.8	76.4	77.0	79.7	79.5	78.2	76.6	78.6
1994													
20 MIN PEAK MW	25916.	24789.	24273.	21556.	20090.	20744.	21359.	21590.	20227.	21208.	24130.	26040.	22660.3
1 HOUR PEAK MW	25673.	24661.	24089.	21412.	19964.	20643.	21265.	21498.	20086.	21002.	23931.	25873.	22508.2
ENERGY GWH	15250.	13476.	14069.	12154.	12102.	11601.	12124.	12361.	11555.	12472.	13513.	14769.	155446.5
ENERGY AV MW	20498.	20054.	18910.	16881.	16266.	16112.	16296.	16614.	16049.	16763.	18768.	19851.	17745.0
*L.F. %	79.8	81.3	78.5	78.8	81.5	78.0	76.6	77.3	79.9	79.8	78.4	76.7	78.8

*LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1995													
20 MIN PEAK MW	26324.	25166.	24630.	21839.	20384.	21054.	21683.	21920.	20523.	21478.	24468.	26423.	
1 HOUR PEAK MW	26075.	25034.	24441.	21693.	20253.	20950.	21587.	21825.	20378.	21267.	24265.	26252.	
ENERGY GWH	15538.	13725.	14323.	12361.	12315.	11802.	12336.	12578.	11753.	12677.	13745.	15029.	158183.1
ENERGY AV MW	20885.	20424.	19251.	17168.	16553.	16392.	16580.	16906.	16324.	17039.	19091.	20200.	18057.4
*L.F. %	80.1	81.6	78.8	79.1	81.7	78.2	76.8	77.5	80.1	80.1	78.7	76.9	79.1
1996													
20 MIN PEAK MW	26399.	25215.	24664.	21823.	20431.	21112.	21751.	21992.	20572.	21446.	24476.	26454.	
1 HOUR PEAK MW	26146.	25082.	24474.	21673.	20299.	21006.	21654.	21895.	20425.	21232.	24269.	26280.	
ENERGY GWH	15669.	13822.	14426.	12431.	12401.	11880.	12417.	12659.	11821.	12730.	13815.	15109.	159178.9
ENERGY AV MW	21061.	20569.	19389.	17265.	16669.	16500.	16689.	17015.	16418.	17110.	19187.	20308.	18171.1
*L.F. %	80.5	82.0	79.2	79.7	82.1	78.5	77.1	77.7	80.4	80.6	79.1	77.3	79.5
1997													
20 MIN PEAK MW	26683.	25471.	24910.	21998.	20682.	21383.	22044.	22293.	20840.	21634.	24745.	26778.	
1 HOUR PEAK MW	26423.	25334.	24713.	21846.	20546.	21275.	21944.	22194.	20689.	21415.	24534.	26599.	
ENERGY GWH	15924.	14051.	14649.	12607.	12601.	12069.	12617.	12865.	12010.	12912.	14029.	15353.	161685.6
ENERGY AV MW	21403.	20909.	19690.	17510.	16936.	16762.	16958.	17292.	16680.	17355.	19484.	20635.	18457.3
*L.F. %	81.0	82.5	79.7	80.2	82.4	78.8	77.3	77.9	80.6	81.0	79.4	77.6	79.8
1998													
20 MIN PEAK MW	26984.	25743.	25169.	22186.	20942.	21661.	22338.	22594.	21106.	21816.	25004.	27088.	
1 HOUR PEAK MW	26717.	25602.	24967.	22030.	20803.	21551.	22235.	22492.	20952.	21591.	24788.	26905.	
ENERGY GWH	16169.	14262.	14864.	12776.	12793.	12251.	12809.	13065.	12191.	13085.	14234.	15588.	164087.0
ENERGY AV MW	21733.	21224.	19979.	17745.	17194.	17015.	17216.	17560.	16932.	17588.	19770.	20951.	18731.4
*L.F. %	81.3	82.9	80.0	80.6	82.7	79.0	77.4	78.1	80.8	81.5	79.8	77.9	80.1
1999													
20 MIN PEAK MW	27422.	26147.	25557.	22491.	21312.	22050.	22747.	23011.	21480.	22110.	25390.	27533.	
1 HOUR PEAK MW	27147.	26002.	25350.	22330.	21168.	21937.	22641.	22906.	21321.	21879.	25167.	27345.	
ENERGY GWH	16480.	14531.	15138.	12996.	13034.	12480.	13051.	13314.	12419.	13311.	14497.	15885.	167136.6
ENERGY AV MW	22150.	21624.	20347.	18050.	17519.	17334.	17541.	17896.	17249.	17892.	20134.	21350.	19079.5
*L.F. %	81.6	83.2	80.3	80.8	82.8	79.0	77.5	78.1	80.9	81.8	80.0	78.1	80.3
2000													
20 MIN PEAK MW	27992.	26677.	26070.	22905.	21784.	22548.	23267.	23538.	21960.	22514.	25900.	28113.	
1 HOUR PEAK MW	27711.	26528.	25856.	22739.	21637.	22430.	23158.	23430.	21795.	22277.	25671.	27918.	
ENERGY GWH	16886.	14859.	15502.	13295.	13354.	12786.	13373.	13646.	12724.	13618.	14845.	16275.	171163.5
ENERGY AV MW	22697.	22112.	20835.	18465.	17949.	17758.	17975.	18341.	17672.	18304.	20618.	21875.	19539.2
*L.F. %	81.9	83.4	80.6	81.2	83.0	79.2	77.6	78.3	81.1	82.2	80.3	78.4	80.5
2001													
20 MIN PEAK MW	28914.	27573.	26968.	23704.	22580.	23388.	24150.	24446.	22816.	23392.	26944.	29274.	
1 HOUR PEAK MW	28620.	27417.	26746.	23530.	22427.	23266.	24036.	24333.	22646.	23144.	26704.	29072.	
ENERGY GWH	17471.	15407.	16052.	13768.	13843.	13261.	13878.	14169.	13218.	14152.	15440.	16940.	177598.8
ENERGY AV MW	23482.	22927.	21575.	19122.	18607.	18418.	18653.	19044.	18358.	19021.	21444.	22768.	20273.8
*L.F. %	82.0	83.6	80.7	81.3	83.0	79.2	77.6	78.3	81.1	82.2	80.3	78.3	80.6

*LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2002													
20 MIN PEAK MW	29600.	28225.	27607.	24261.	23107.	23936.	24717.	25022.	23351.	23945.	27586.	29976.	25944.4
1 HOUR PEAK MW	29298.	28067.	27379.	24083.	22950.	23810.	24601.	24907.	23176.	23689.	27340.	29769.	25755.8
ENERGY GWH	17890.	15776.	16437.	14095.	14172.	13575.	14208.	14506.	13531.	14489.	15810.	17346.	181835.2
ENERGY AV MW	24046.	23476.	22092.	19576.	19049.	18854.	19097.	19497.	18793.	19475.	21958.	23315.	20757.4
*L.F. %	82.1	83.6	80.7	81.3	83.0	79.2	77.6	78.3	81.1	82.2	80.3	78.3	80.6
2003													
20 MIN PEAK MW	30165.	28763.	28131.	24717.	23539.	24386.	25184.	25496.	23792.	24397.	28114.	30554.	26436.5
1 HOUR PEAK MW	29856.	28600.	27898.	24536.	23380.	24259.	25065.	25379.	23612.	24137.	27864.	30343.	26244.2
ENERGY GWH	18237.	16080.	16754.	14364.	14443.	13834.	14480.	14784.	13789.	14767.	16114.	17683.	185327.1
ENERGY AV MW	24512.	23928.	22519.	19950.	19413.	19214.	19462.	19871.	19152.	19848.	22380.	23767.	21156.1
*L.F. %	82.1	83.7	80.7	81.3	83.0	79.2	77.6	78.3	81.1	82.2	80.3	78.3	80.6
2004													
20 MIN PEAK MW	30337.	28923.	28287.	24843.	23664.	24519.	25323.	25637.	23919.	24521.	28271.	30731.	26581.2
1 HOUR PEAK MW	30027.	28760.	28052.	24660.	23503.	24390.	25203.	25519.	23739.	24259.	28017.	30518.	26387.3
ENERGY GWH	18357.	16150.	16860.	14451.	14532.	13917.	14568.	14875.	13872.	14856.	16216.	17798.	186454.1
ENERGY AV MW	24673.	24033.	22661.	20071.	19532.	19330.	19581.	19993.	19267.	19967.	22522.	23922.	21284.7
*L.F. %	82.2	83.6	80.8	81.4	83.1	79.3	77.7	78.3	81.2	82.3	80.4	78.4	80.7
2005													
20 MIN PEAK MW	30609.	29180.	28535.	25052.	23868.	24732.	25545.	25864.	24124.	24728.	28519.	31009.	26813.8
1 HOUR PEAK MW	30296.	29014.	28298.	24868.	23704.	24600.	25423.	25743.	23942.	24462.	28265.	30793.	26617.4
ENERGY GWH	18533.	16335.	17020.	14582.	14666.	14045.	14703.	15013.	14000.	14993.	16368.	17968.	188226.0
ENERGY AV MW	24910.	24308.	22876.	20253.	19712.	19507.	19762.	20179.	19444.	20151.	22734.	24151.	21487.0
*L.F. %	82.2	83.8	80.8	81.4	83.2	79.3	77.7	78.4	81.2	82.4	80.4	78.4	80.7
2006													
20 MIN PEAK MW	31042.	29589.	28937.	25398.	24196.	25074.	25902.	26224.	24458.	25068.	28920.	31449.	27188.1
1 HOUR PEAK MW	30724.	29422.	28695.	25210.	24031.	24941.	25778.	26103.	24273.	24798.	28661.	31230.	26988.8
ENERGY GWH	18802.	16569.	17264.	14789.	14874.	14244.	14912.	15227.	14197.	15205.	16603.	18228.	190916.5
ENERGY AV MW	25271.	24657.	23205.	20541.	19993.	19783.	20043.	20467.	19719.	20437.	23060.	24500.	21794.1
*L.F. %	82.3	83.8	80.9	81.5	83.2	79.3	77.8	78.4	81.2	82.4	80.5	78.5	80.8
2007													
20 MIN PEAK MW	31447.	29972.	29309.	25718.	24503.	25394.	26232.	26561.	24769.	25384.	29294.	31860.	27537.0
1 HOUR PEAK MW	31123.	29801.	29064.	25527.	24334.	25259.	26108.	26437.	24580.	25111.	29031.	31638.	27334.5
ENERGY GWH	19054.	16788.	17494.	14982.	15068.	14429.	15107.	15427.	14382.	15403.	16823.	18472.	193429.0
ENERGY AV MW	25610.	24982.	23513.	20808.	20253.	20041.	20305.	20736.	19975.	20703.	23365.	24827.	22080.9
*L.F. %	82.3	83.8	80.9	81.5	83.2	79.3	77.8	78.4	81.3	82.4	80.5	78.5	80.8
2008													
20 MIN PEAK MW	31859.	30362.	29689.	26045.	24815.	25719.	26571.	26904.	25086.	25706.	29675.	32279.	27892.5
1 HOUR PEAK MW	31530.	30190.	29440.	25851.	24644.	25583.	26444.	26779.	24895.	25430.	29407.	32054.	27687.2
ENERGY GWH	19312.	16979.	17729.	15179.	15268.	14619.	15306.	15631.	14572.	15608.	17047.	18721.	195971.9
ENERGY AV MW	25957.	25267.	23829.	21083.	20522.	20304.	20573.	21010.	20238.	20978.	23677.	25162.	22371.2
*L.F. %	82.3	83.7	80.9	81.6	83.3	79.4	77.8	78.5	81.3	82.5	80.5	78.5	80.8

*LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2009													
20 MIN PEAK MW	32254.	30738.	30055.	26358.	25115.	26032.	26896.	27234.	25389.	26016.	30041.	32682.	28234.2
1 HOUR PEAK MW	31921.	30561.	29803.	26162.	24942.	25894.	26767.	27107.	25195.	25734.	29768.	32453.	28025.6
ENERGY GWH	19559.	17228.	17953.	15367.	15458.	14801.	15498.	15828.	14753.	15802.	17263.	18959.	198467.5
ENERGY AV MW	26289.	25638.	24130.	21343.	20777.	20556.	20831.	21274.	20490.	21239.	23976.	25483.	22656.1
*L.F. %	82.4	83.9	81.0	81.6	83.3	79.4	77.8	78.5	81.3	82.5	80.5	78.5	80.8
2010													
20 MIN PEAK MW	32686.	31146.	30453.	26702.	25443.	26373.	27250.	27594.	25722.	26355.	30439.	33121.	28607.1
1 HOUR PEAK MW	32348.	30969.	30198.	26503.	25266.	26233.	27120.	27464.	25525.	26069.	30164.	32889.	28395.6
ENERGY GWH	19826.	17462.	18196.	15573.	15666.	14999.	15706.	16041.	14950.	16013.	17496.	19219.	201149.1
ENERGY AV MW	26648.	25985.	24457.	21628.	21057.	20832.	21110.	21560.	20764.	21523.	24301.	25832.	22962.2
*L.F. %	82.4	83.9	81.0	81.6	83.3	79.4	77.8	78.5	81.3	82.6	80.6	78.5	80.9

*LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1988													
20 MIN PEAK MW	21575.	20615.	20141.	18035.	16787.	17336.	17639.	18049.	16944.	17801.	20127.	21700.	18895.8
1 HOUR PEAK MW	21352.	20486.	19970.	17894.	16660.	17230.	17539.	17948.	16806.	17611.	19943.	21559.	18750.0
ENERGY GWH	12377.	11313.	11388.	9828.	9761.	9390.	9725.	9976.	9333.	10106.	10930.	11957.	126082.9
ENERGY AV MW	16636.	16255.	15306.	13650.	13120.	13042.	13071.	13408.	12963.	13583.	15180.	16071.	14353.7
*L.F. %	77.9	79.3	76.6	76.3	78.8	75.7	74.5	74.7	77.1	77.1	76.1	74.5	76.6
1989													
20 MIN PEAK MW	22123.	21218.	20804.	18615.	17310.	17880.	18352.	18626.	17460.	18280.	20701.	22274.	19470.2
1 HOUR PEAK MW	21896.	21088.	20628.	18471.	17182.	17774.	18251.	18525.	17319.	18085.	20513.	22130.	19321.7
ENERGY GWH	12695.	11249.	11769.	10167.	10095.	9710.	10132.	10330.	9660.	10404.	11274.	12307.	129791.6
ENERGY AV MW	17063.	16740.	15819.	14121.	13569.	13486.	13619.	13884.	13417.	13984.	15658.	16542.	14816.4
*L.F. %	77.9	79.4	76.7	76.4	79.0	75.9	74.6	74.9	77.5	77.3	76.3	74.7	76.7
1990													
20 MIN PEAK MW	22664.	21729.	21299.	19027.	17720.	18300.	18795.	19181.	17810.	18631.	21106.	22745.	19917.6
1 HOUR PEAK MW	22429.	21596.	21117.	18880.	17589.	18191.	18691.	19077.	17665.	18432.	20914.	22598.	19765.3
ENERGY GWH	13035.	11551.	12077.	10423.	10368.	9965.	10403.	10563.	9883.	10634.	11521.	12591.	133013.5
ENERGY AV MW	17520.	17188.	16232.	14477.	13935.	13840.	13983.	14197.	13727.	14293.	16001.	16923.	15184.2
*L.F. %	78.1	79.6	76.9	76.7	79.2	76.1	74.8	74.4	77.7	77.5	76.5	74.9	76.8
1991													
20 MIN PEAK MW	23140.	22177.	21736.	19387.	18050.	18652.	19245.	19459.	18227.	19084.	21660.	23389.	20350.2
1 HOUR PEAK MW	22897.	22039.	21548.	19235.	17914.	18540.	19138.	19353.	18078.	18877.	21461.	23237.	20193.0
ENERGY GWH	13342.	11814.	12352.	10646.	10594.	10174.	10636.	10848.	10140.	10922.	11848.	12972.	136288.8
ENERGY AV MW	17933.	17580.	16602.	14787.	14239.	14131.	14296.	14580.	14084.	14680.	16456.	17436.	15558.1
*L.F. %	78.3	79.8	77.0	76.9	79.5	76.2	74.7	75.3	77.9	77.8	76.7	75.0	77.0
1992													
20 MIN PEAK MW	23811.	22798.	22329.	19876.	18488.	19104.	19709.	19916.	18624.	19492.	22155.	23932.	20853.4
1 HOUR PEAK MW	23559.	22657.	22134.	19719.	18348.	18988.	19599.	19807.	18469.	19278.	21949.	23775.	20690.7
ENERGY GWH	13774.	12619.	12735.	10963.	10906.	10458.	10943.	11158.	10418.	11223.	12182.	13350.	140731.3
ENERGY AV MW	18513.	18131.	17117.	15227.	14659.	14525.	14708.	14998.	14470.	15085.	16920.	17944.	16021.3
*L.F. %	78.6	80.0	77.3	77.2	79.9	76.5	75.0	75.7	78.3	78.2	77.1	75.5	77.4
1993													
20 MIN PEAK MW	24396.	23346.	22860.	20314.	18890.	19526.	20154.	20366.	19028.	19922.	22683.	24523.	21334.0
1 HOUR PEAK MW	24136.	23201.	22659.	20153.	18746.	19407.	20041.	20254.	18869.	19700.	22471.	24360.	21166.3
ENERGY GWH	14194.	12550.	13115.	11283.	11224.	10762.	11265.	11485.	10721.	11552.	12547.	13750.	144448.4
ENERGY AV MW	19078.	18676.	17628.	15671.	15086.	14948.	15142.	15437.	14891.	15527.	17427.	18481.	16489.5
*L.F. %	79.0	80.5	77.8	77.8	80.5	77.0	75.6	76.2	78.9	78.8	77.6	75.9	77.9
1994													
20 MIN PEAK MW	24822.	23744.	23243.	20632.	19193.	19842.	20486.	20699.	19328.	20219.	23043.	24932.	21682.0
1 HOUR PEAK MW	24582.	23620.	23061.	20493.	19071.	19744.	20394.	20609.	19190.	20017.	22849.	24767.	21533.2
ENERGY GWH	14503.	12821.	13406.	11517.	11462.	10983.	11501.	11721.	10932.	11782.	12798.	14010.	147438.5
ENERGY AV MW	19493.	19079.	18019.	15996.	15406.	15255.	15458.	15754.	15183.	15836.	17775.	18831.	16830.9
*L.F. %	79.3	80.8	78.1	78.1	80.8	77.3	75.8	76.4	79.1	79.1	77.8	76.0	78.2

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1995													
20 MIN PEAK MW	25245.	24135.	23616.	20935.	19503.	20168.	20827.	21046.	19640.	20505.	23396.	25330.	22028.9
1 HOUR PEAK MW	24998.	24007.	23430.	20793.	19378.	20068.	20734.	20954.	19498.	20299.	23197.	25160.	21876.3
ENERGY GWH	14796.	13077.	13668.	11732.	11683.	11193.	11721.	11946.	11138.	11994.	13036.	14274.	150257.5
ENERGY AV MW	19888.	19459.	18371.	16294.	15703.	15546.	15754.	16056.	15469.	16121.	18106.	19186.	17152.7
*L.F. %	79.6	81.1	78.4	78.4	81.0	77.5	76.0	76.6	79.3	79.4	78.1	76.3	78.4
1996													
20 MIN PEAK MW	25342.	24208.	23674.	20944.	19573.	20248.	20918.	21140.	19711.	20499.	23428.	25384.	22089.1
1 HOUR PEAK MW	25092.	24079.	23486.	20799.	19446.	20146.	20823.	21046.	19567.	20289.	23226.	25212.	21934.2
ENERGY GWH	14928.	13178.	13774.	11805.	11772.	11274.	11805.	12030.	11210.	12052.	13109.	14358.	151294.8
ENERGY AV MW	20065.	19610.	18513.	16397.	15822.	15658.	15867.	16170.	15569.	16198.	18207.	19299.	17271.1
*L.F. %	80.0	81.4	78.8	78.8	81.4	77.7	76.2	76.8	79.6	79.8	78.4	76.5	78.7
1997													
20 MIN PEAK MW	25621.	24461.	23916.	21120.	19818.	20514.	21204.	21435.	19973.	20682.	23690.	25701.	22344.6
1 HOUR PEAK MW	25364.	24328.	23723.	20971.	19688.	20410.	21106.	21338.	19825.	20467.	23483.	25524.	22185.6
ENERGY GWH	15178.	13403.	13994.	11980.	11967.	11460.	12002.	12233.	11395.	12229.	13319.	14596.	153755.1
ENERGY AV MW	20401.	19944.	18809.	16638.	16085.	15916.	16131.	16443.	15826.	16437.	18498.	19619.	17552.0
*L.F. %	80.4	82.0	79.3	79.3	81.7	78.0	76.4	77.1	79.8	80.3	78.8	76.9	79.1
1998													
20 MIN PEAK MW	25919.	24732.	24175.	21310.	20077.	20790.	21498.	21735.	20237.	20866.	23948.	26009.	22608.0
1 HOUR PEAK MW	25656.	24595.	23977.	21158.	19943.	20683.	21398.	21636.	20086.	20645.	23736.	25828.	22445.1
ENERGY GWH	15418.	13611.	14206.	12146.	12155.	11638.	12191.	12420.	11572.	12399.	13519.	14825.	156107.1
ENERGY AV MW	20724.	20254.	19094.	16869.	16337.	16164.	16385.	16704.	16072.	16666.	18777.	19926.	17820.4
*L.F. %	80.8	82.3	79.6	79.7	81.9	78.1	76.6	77.2	80.0	80.7	79.1	77.1	79.4
1999													
20 MIN PEAK MW	26351.	25131.	24559.	21613.	20440.	21174.	21902.	22145.	20606.	21157.	24328.	26447.	22987.7
1 HOUR PEAK MW	26081.	24990.	24355.	21457.	20303.	21064.	21799.	22044.	20450.	20930.	24109.	26261.	22820.2
ENERGY GWH	15720.	13873.	14474.	12359.	12390.	11861.	12427.	12671.	11794.	12618.	13774.	15113.	159074.7
ENERGY AV MW	21129.	20644.	19454.	17166.	16653.	16474.	16703.	17031.	16381.	16960.	19130.	20314.	18159.2
*L.F. %	81.0	82.6	79.9	80.0	82.0	78.2	76.6	77.3	80.1	81.0	79.3	77.4	79.6
2000													
20 MIN PEAK MW	26908.	25649.	25059.	22020.	20900.	21657.	22408.	22660.	21071.	21550.	24823.	27011.	23476.3
1 HOUR PEAK MW	26629.	25504.	24848.	21858.	20758.	21544.	22302.	22555.	20910.	21316.	24598.	26819.	23303.5
ENERGY GWH	16109.	14188.	14823.	12645.	12696.	12153.	12735.	12987.	12085.	12910.	14107.	15486.	162924.5
ENERGY AV MW	21652.	21113.	19924.	17562.	17064.	16880.	17117.	17456.	16784.	17352.	19593.	20815.	18598.7
*L.F. %	81.3	82.8	80.2	80.3	82.2	78.4	76.7	77.4	80.3	81.4	79.7	77.6	79.8
2001													
20 MIN PEAK MW	27810.	26526.	25939.	22802.	21679.	22480.	23275.	23550.	21909.	22405.	25838.	28142.	24362.9
1 HOUR PEAK MW	27520.	26375.	25720.	22634.	21532.	22362.	23164.	23441.	21741.	22161.	25604.	27943.	24183.0
ENERGY GWH	16676.	14720.	15359.	13104.	13170.	12614.	13225.	13495.	12563.	13424.	14680.	16127.	169156.9
ENERGY AV MW	22414.	21905.	20644.	18200.	17702.	17519.	17775.	18138.	17448.	18044.	20389.	21676.	19310.2
*L.F. %	81.4	83.1	80.3	80.4	82.2	78.3	76.7	77.4	80.3	81.4	79.6	77.6	79.9

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2002													
20 MIN PEAK MW	28486.	27171.	26569.	23355.	22201.	23023.	23838.	24121.	22439.	22950.	26470.	28833.	24954.7
1 HOUR PEAK MW	28189.	27016.	26345.	23183.	22050.	22902.	23725.	24009.	22267.	22700.	26230.	28628.	24770.3
ENERGY GWH	17086.	15082.	15737.	13425.	13492.	12922.	13548.	13825.	12870.	13754.	15041.	16524.	173304.5
ENERGY AV MW	22965.	22443.	21151.	18646.	18135.	17947.	18210.	18582.	17875.	18486.	20890.	22209.	19783.6
*L.F. %	81.5	83.1	80.3	80.4	82.2	78.4	76.8	77.4	80.3	81.4	79.6	77.6	79.9
2003													
20 MIN PEAK MW	29045.	27704.	27090.	23810.	22633.	23473.	24305.	24594.	22878.	23400.	26993.	29405.	25444.2
1 HOUR PEAK MW	28742.	27546.	26861.	23634.	22479.	23349.	24189.	24480.	22703.	23145.	26748.	29196.	25256.0
ENERGY GWH	17427.	15381.	16050.	13691.	13759.	13177.	13816.	14099.	13124.	14026.	15340.	16854.	176744.0
ENERGY AV MW	23423.	22889.	21572.	19015.	18493.	18301.	18570.	18950.	18228.	18852.	21306.	22653.	20176.3
*L.F. %	81.5	83.1	80.3	80.5	82.3	78.4	76.8	77.4	80.3	81.5	79.7	77.6	79.9
2004													
20 MIN PEAK MW	29231.	27877.	27258.	23950.	22772.	23618.	24458.	24749.	23019.	23537.	27161.	29594.	25601.9
1 HOUR PEAK MW	28924.	27718.	27027.	23773.	22616.	23494.	24341.	24634.	22842.	23280.	26914.	29383.	25412.1
ENERGY GWH	17552.	15463.	16163.	13784.	13854.	13267.	13912.	14197.	13214.	14122.	15448.	16974.	177945.1
ENERGY AV MW	23591.	23006.	21724.	19144.	18621.	18427.	18699.	19082.	18353.	18981.	21455.	22814.	20313.4
*L.F. %	81.6	83.0	80.4	80.5	82.3	78.4	76.8	77.5	80.3	81.5	79.7	77.6	79.9
2005													
20 MIN PEAK MW	29510.	28142.	27516.	24170.	22984.	23840.	24690.	24984.	23234.	23752.	27418.	29878.	25843.3
1 HOUR PEAK MW	29200.	27981.	27282.	23990.	22827.	23714.	24572.	24868.	23055.	23492.	27168.	29665.	25651.2
ENERGY GWH	17730.	15646.	16325.	13919.	13992.	13399.	14051.	14339.	13345.	14261.	15602.	17145.	179753.7
ENERGY AV MW	23831.	23282.	21942.	19332.	18806.	18610.	18885.	19273.	18535.	19168.	21670.	23045.	20519.8
*L.F. %	81.6	83.2	80.4	80.6	82.4	78.5	76.9	77.5	80.4	81.6	79.8	77.7	80.0
2006													
20 MIN PEAK MW	29944.	28554.	27918.	24518.	23317.	24187.	25050.	25349.	23571.	24095.	27819.	30319.	26220.2
1 HOUR PEAK MW	29629.	28390.	27680.	24336.	23157.	24059.	24930.	25231.	23389.	23830.	27565.	30102.	26025.1
ENERGY GWH	17996.	15880.	16569.	14125.	14200.	13597.	14259.	14552.	13543.	14472.	15835.	17403.	182430.9
ENERGY AV MW	24188.	23630.	22270.	19618.	19085.	18885.	19166.	19559.	18809.	19452.	21993.	23391.	20825.4
*L.F. %	81.6	83.2	80.5	80.6	82.4	78.5	76.9	77.5	80.4	81.6	79.8	77.7	80.0
2007													
20 MIN PEAK MW	30350.	28939.	28294.	24844.	23628.	24511.	25387.	25691.	23887.	24415.	28194.	30731.	26572.4
1 HOUR PEAK MW	30030.	28773.	28053.	24659.	23466.	24381.	25265.	25571.	23702.	24146.	27936.	30512.	26374.4
ENERGY GWH	18246.	16099.	16798.	14318.	14394.	13783.	14455.	14752.	13728.	14670.	16054.	17645.	184941.2
ENERGY AV MW	24525.	23957.	22578.	19886.	19347.	19143.	19428.	19828.	19066.	19718.	22297.	23716.	21112.0
*L.F. %	81.7	83.3	80.5	80.6	82.4	78.5	76.9	77.5	80.4	81.7	79.8	77.7	80.0
2008													
20 MIN PEAK MW	30763.	29331.	28677.	25176.	23945.	24841.	25730.	26039.	24208.	24741.	28577.	31151.	26931.7
1 HOUR PEAK MW	30439.	29163.	28432.	24988.	23781.	24710.	25607.	25917.	24021.	24468.	28315.	30928.	26730.8
ENERGY GWH	18502.	16291.	17032.	14516.	14593.	13974.	14655.	14956.	13917.	14873.	16278.	17891.	187478.4
ENERGY AV MW	24868.	24242.	22893.	20161.	19615.	19408.	19697.	20103.	19330.	19991.	22608.	24048.	21401.6
*L.F. %	81.7	83.1	80.5	80.7	82.5	78.5	76.9	77.6	80.5	81.7	79.8	77.8	80.1

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2009													
20 MIN PEAK MW	31161.	29709.	29045.	25495.	24250.	25159.	26061.	26373.	24517.	25054.	28944.	31555.	27276.8
1 HOUR PEAK MW	30832.	29538.	28797.	25304.	24083.	25025.	25935.	26250.	24327.	24777.	28678.	31329.	27073.0
ENERGY GWH	18747.	16539.	17256.	14705.	14784.	14156.	14847.	15153.	14099.	15067.	16491.	18128.	189971.9
ENERGY AV MW	25198.	24611.	23194.	20423.	19871.	19661.	19955.	20366.	19582.	20251.	22905.	24366.	21686.3
*L.F. %	81.7	83.3	80.5	80.7	82.5	78.6	76.9	77.6	80.5	81.7	79.9	77.8	80.1
2010													
20 MIN PEAK MW	31594.	30120.	29446.	25843.	24582.	25505.	26420.	26738.	24853.	25395.	29344.	31995.	27652.8
1 HOUR PEAK MW	31260.	29946.	29194.	25650.	24413.	25369.	26293.	26612.	24660.	25115.	29075.	31765.	27446.0
ENERGY GWH	19013.	16772.	17500.	14910.	14991.	14354.	15055.	15365.	14296.	15278.	16724.	18385.	192643.4
ENERGY AV MW	25555.	24958.	23521.	20708.	20150.	19936.	20235.	20652.	19856.	20535.	23228.	24711.	21991.3
*L.F. %	81.8	83.3	80.6	80.7	82.5	78.6	77.0	77.6	80.5	81.8	79.9	77.8	80.1

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1988													
20 MIN PEAK MW	1033.	1020.	971.	915.	890.	864.	871.	858.	912.	950.	1018.	1056.	946.5
1 HOUR PEAK MW	1030.	1015.	967.	909.	885.	860.	868.	855.	908.	944.	1014.	1052.	942.2
ENERGY GWH	645.	590.	582.	552.	558.	540.	547.	557.	544.	598.	611.	645.	6969.2
ENERGY AV MW	867.	848.	782.	767.	750.	750.	735.	748.	756.	804.	848.	867.	793.4
*L.F. %	84.2	83.5	80.9	84.4	84.7	87.2	84.7	87.5	83.3	85.2	83.6	82.4	84.2
1989													
20 MIN PEAK MW	1076.	1054.	1000.	955.	928.	905.	909.	875.	921.	953.	1029.	1070.	972.9
1 HOUR PEAK MW	1073.	1049.	996.	949.	923.	901.	906.	872.	916.	947.	1025.	1065.	968.5
ENERGY GWH	668.	586.	595.	575.	582.	566.	570.	567.	550.	601.	618.	654.	7135.1
ENERGY AV MW	898.	873.	800.	799.	783.	787.	767.	763.	764.	808.	859.	880.	814.5
*L.F. %	83.7	83.2	80.3	84.2	84.8	87.3	84.6	87.5	83.4	85.3	83.8	82.6	84.1
1990													
20 MIN PEAK MW	1069.	1047.	992.	935.	895.	866.	869.	857.	909.	949.	1033.	1071.	958.2
1 HOUR PEAK MW	1066.	1042.	989.	929.	889.	861.	865.	854.	905.	943.	1029.	1067.	953.7
ENERGY GWH	677.	593.	601.	574.	573.	552.	556.	569.	554.	611.	634.	668.	7160.1
ENERGY AV MW	910.	882.	808.	797.	770.	766.	748.	764.	769.	821.	880.	898.	817.4
*L.F. %	85.3	84.6	81.6	85.8	86.5	89.0	86.4	89.5	85.0	87.1	85.5	84.2	85.7
1991													
20 MIN PEAK MW	1074.	1053.	999.	942.	903.	875.	881.	871.	92(	969.	1057.	1108.	972.1
1 HOUR PEAK MW	1071.	1048.	996.	936.	898.	870.	877.	868.	92[illegible].	963.	1053.	1104.	967.5
ENERGY GWH	686.	601.	611.	585.	585.	565.	570.	585.	571.	631.	656.	698.	7345.8
ENERGY AV MW	922.	895.	822.	812.	786.	784.	767.	786.	793.	848.	911.	938.	838.6
*L.F. %	86.0	85.4	82.5	86.8	87.4	90.1	87.4	90.6	86.0	88.1	86.5	85.0	86.7
1992													
20 MIN PEAK MW	1109.	1086.	1028.	967.	926.	895.	898.	886.	940.	982.	1069.	1119.	992.6
1 HOUR PEAK MW	1106.	1081.	1025.	961.	920.	890.	894.	883.	936.	975.	1065.	1114.	987.9
ENERGY GWH	716.	649.	633.	607.	607.	584.	588.	602.	586.	646.	670.	710.	7599.5
ENERGY AV MW	963.	932.	851.	843.	816.	811.	791.	810.	813.	869.	930.	955.	865.1
*L.F. %	87.0	86.2	82.9	87.7	88.6	91.1	88.4	91.6	86.9	89.0	87.3	85.7	87.6
1993													
20 MIN PEAK MW	1123.	1102.	1046.	986.	947.	918.	924.	915.	974.	1019.	1112.	1167.	1019.9
1 HOUR PEAK MW	1119.	1097.	1042.	980.	941.	913.	921.	911.	969.	1012.	1108.	1162.	1015.1
ENERGY GWH	730.	641.	649.	624.	626.	604.	610.	627.	611.	676.	701.	744.	7844.3
ENERGY AV MW	982.	954.	873.	866.	842.	839.	820.	842.	848.	908.	974.	1000.	895.5
*L.F. %	87.7	86.9	83.7	88.4	89.4	91.9	88.9	92.4	87.5	89.7	87.9	86.1	88.2
1994													
20 MIN PEAK MW	1144.	1122.	1065.	1004.	964.	934.	940.	930.	991.	1035.	1130.	1186.	1037.1
1 HOUR PEAK MW	1142.	1119.	1062.	997.	959.	929.	938.	927.	987.	1030.	1127.	1181.	1033.1
ENERGY GWH	747.	655.	662.	637.	640.	617.	623.	640.	623.	690.	715.	759.	8008.0
ENERGY AV MW	1004.	975.	890.	885.	860.	857.	837.	860.	866.	927.	993.	1021.	914.2
*L.F. %	87.9	87.1	83.8	88.7	89.7	92.2	89.3	92.7	87.7	90.0	88.1	86.4	88.5

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
1995													
20 MIN PEAK MW	1132.	1109.	1050.	987.	949.	919.	925.	914.	977.	1019.	1117.	1174.	1022.7
1 HOUR PEAK MW	1130.	1105.	1047.	981.	944.	913.	922.	911.	972.	1014.	1114.	1169.	1018.6
ENERGY GWH	742.	648.	655.	629.	633.	609.	615.	632.	615.	683.	709.	754.	7925.6
ENERGY AV MW	998.	964.	881.	874.	850.	846.	826.	850.	855.	918.	985.	1014.	904.7
*L.F. %	88.3	87.2	84.1	89.1	90.1	92.7	89.7	93.2	87.9	90.5	88.4	86.7	88.8
1996													
20 MIN PEAK MW	1110.	1087.	1027.	962.	928.	897.	903.	893.	956.	995.	1093.	1152.	1000.3
1 HOUR PEAK MW	1108.	1083.	1024.	956.	923.	892.	900.	890.	952.	990.	1090.	1146.	996.2
ENERGY GWH	740.	645.	652.	625.	630.	606.	611.	629.	612.	679.	705.	751.	7884.1
ENERGY AV MW	995.	959.	876.	868.	846.	842.	821.	845.	849.	912.	979.	1009.	900.0
*L.F. %	89.8	88.6	85.6	90.8	91.7	94.4	91.2	95.0	89.3	92.2	89.8	88.0	90.3
1997													
20 MIN PEAK MW	1117.	1093.	1031.	965.	935.	904.	911.	900.	965.	1000.	1102.	1162.	1007.0
1 HOUR PEAK MW	1114.	1089.	1028.	959.	930.	899.	908.	897.	961.	995.	1098.	1156.	1002.8
ENERGY GWH	746.	649.	655.	628.	633.	609.	614.	632.	615.	682.	710.	757.	7930.4
ENERGY AV MW	1002.	965.	880.	872.	851.	846.	826.	850.	854.	917.	986.	1017.	905.3
*L.F. %	89.9	88.6	85.6	91.0	91.5	94.2	91.0	94.8	88.9	92.2	89.8	87.9	90.3
1998													
20 MIN PEAK MW	1120.	1095.	1032.	964.	939.	906.	913.	902.	969.	1000.	1104.	1166.	1009.1
1 HOUR PEAK MW	1117.	1091.	1029.	958.	933.	901.	910.	899.	965.	995.	1100.	1160.	1004.8
ENERGY GWH	751.	652.	658.	631.	637.	613.	618.	636.	619.	686.	715.	762.	7979.9
ENERGY AV MW	1010.	970.	884.	876.	857.	851.	831.	855.	860.	923.	993.	1025.	911.0
*L.F. %	90.4	88.9	85.9	91.4	91.8	94.5	91.3	95.1	89.1	92.8	90.2	88.4	90.7
1999													
20 MIN PEAK MW	1127.	1103.	1038.	968.	946.	913.	920.	909.	977.	1004.	1111.	1175.	1016.0
1 HOUR PEAK MW	1125.	1098.	1034.	961.	941.	908.	917.	906.	973.	999.	1108.	1169.	1011.5
ENERGY GWH	760.	659.	664.	636.	644.	619.	624.	643.	625.	693.	723.	771.	8061.9
ENERGY AV MW	1021.	980.	893.	883.	865.	860.	839.	864.	868.	932.	1004.	1037.	920.3
*L.F. %	90.8	89.2	86.3	91.9	92.0	94.7	91.5	95.4	89.3	93.3	90.6	88.7	91.0
2000													
20 MIN PEAK MW	1144.	1119.	1052.	980.	962.	928.	935.	923.	994.	1017.	1128.	1193.	1031.1
1 HOUR PEAK MW	1142.	1114.	1048.	973.	956.	922.	932.	920.	989.	1012.	1124.	1187.	1026.6
ENERGY GWH	777.	672.	678.	649.	659.	633.	638.	658.	639.	708.	739.	789.	8238.9
ENERGY AV MW	1044.	999.	911.	902.	885.	879.	858.	884.	888.	952.	1026.	1060.	940.5
*L.F. %	91.4	89.7	86.9	92.7	92.6	95.3	92.1	96.1	89.8	94.1	91.3	89.3	91.6
2001													
20 MIN PEAK MW	1165.	1140.	1072.	998.	982.	947.	955.	944.	1018.	1042.	1158.	1227.	1054.0
1 HOUR PEAK MW	1163.	1135.	1068.	991.	976.	941.	951.	940.	1013.	1036.	1154.	1221.	1049.2
ENERGY GWH	795.	687.	693.	664.	674.	647.	653.	674.	655.	727.	760.	812.	8441.8
ENERGY AV MW	1068.	1023.	931.	922.	906.	899.	878.	906.	910.	977.	1055.	1092.	963.7
*L.F. %	91.8	90.1	87.2	93.0	92.8	95.6	92.3	96.4	89.9	94.3	91.4	89.4	91.8

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2002													
20 MIN PEAK MW	1177.	1151.	1081.	1005.	988.	953.	961.	949.	1025.	1051.	1170.	1241.	1062.7
1 HOUR PEAK MW	1174.	1146.	1077.	998.	982.	947.	958.	946.	1021.	1045.	1166.	1234.	1057.8
ENERGY GWH	804.	694.	700.	670.	681.	654.	660.	681.	762.	735.	768.	822.	8530.8
ENERGY AV MW	1081.	1033.	941.	931.	915.	908.	886.	915.	919.	988.	1067.	1105.	973.8
*L.F. %	92.1	90.2	87.4	93.3	93.1	95.9	92.6	96.7	90.0	94.6	91.5	89.6	92.1
2003													
20 MIN PEAK MW	1183.	1157.	1085.	1008.	991.	954.	963.	951.	1029.	1055.	1176.	1249.	1066.8
1 HOUR PEAK MW	1181.	1152.	1081.	1001.	985.	948.	960.	948.	1024.	1048.	1172.	1242.	1061.8
ENERGY GWH	811.	698.	704.	674.	684.	657.	663.	684.	665.	740.	774.	829.	8583.2
ENERGY AV MW	1090.	1039.	946.	936.	920.	912.	891.	920.	923.	995.	1075.	1114.	979.8
*L.F. %	92.3	90.2	87.5	93.5	93.4	96.2	92.8	97.1	90.2	94.9	91.7	89.7	92.3
2004													
20 MIN PEAK MW	1172.	1145.	1073.	995.	978.	941.	950.	938.	1016.	1042.	1164.	1238.	1054.5
1 HOUR PEAK MW	1169.	1140.	1069.	988.	972.	935.	947.	935.	1011.	1036.	1161.	1231.	1049.5
ENERGY GWH	805.	691.	698.	667.	678.	650.	656.	678.	658.	734.	768.	824.	8509.0
ENERGY AV MW	1082.	1028.	938.	927.	911.	903.	882.	912.	914.	987.	1067.	1107.	971.3
*L.F. %	92.6	90.1	87.7	93.8	93.7	96.5	93.2	97.5	90.4	95.3	91.9	89.9	92.6
2005													
20 MIN PEAK MW	1165.	1138.	1065.	987.	970.	933.	941.	929.	1008.	1034.	1158.	1232.	1046.6
1 HOUR PEAK MW	1162.	1133.	1061.	979.	963.	926.	938.	925.	1003.	1027.	1154.	1226.	1041.5
ENERGY GWH	803.	689.	695.	663.	674.	646.	652.	675.	655.	731.	766.	822.	8472.3
ENERGY AV MW	1080.	1025.	934.	921.	906.	898.	877.	907.	909.	983.	1064.	1105.	967.2
*L.F. %	92.9	90.5	88.0	94.1	94.1	96.9	93.5	98.0	90.6	95.7	92.2	90.2	92.9
2006													
20 MIN PEAK MW	1165.	1138.	1064.	984.	967.	929.	938.	926.	1007.	1032.	1158.	1233.	1045.2
1 HOUR PEAK MW	1163.	1133.	1060.	976.	961.	923.	935.	922.	1001.	1026.	1154.	1226.	1040.0
ENERGY GWH	806.	690.	696.	664.	675.	647.	653.	675.	655.	733.	768.	825.	8485.6
ENERGY AV MW	1083.	1026.	935.	922.	907.	898.	878.	908.	910.	985.	1067.	1109.	968.7
*L.F. %	93.2	90.6	88.2	94.4	94.4	97.3	93.9	98.4	90.9	96.0	92.4	90.4	93.1
2007													
20 MIN PEAK MW	1165.	1137.	1062.	981.	964.	925.	934.	922.	1004.	1030.	1157.	1234.	1042.9
1 HOUR PEAK MW	1162.	1132.	1058.	973.	957.	919.	931.	918.	998.	1023.	1153.	1227.	1037.6
ENERGY GWH	808.	690.	696.	663.	675.	646.	652.	675.	655.	733.	769.	827.	8487.8
ENERGY AV MW	1085.	1026.	935.	921.	907.	897.	877.	907.	909.	986.	1068.	1112.	968.9
*L.F. %	93.4	90.7	88.4	94.7	94.8	97.6	94.2	98.8	91.1	96.4	92.6	90.6	93.4
2008													
20 MIN PEAK MW	1164.	1136.	1059.	978.	960.	921.	931.	918.	1001.	1027.	1157.	1235.	1040.5
1 HOUR PEAK MW	1161.	1130.	1055.	969.	954.	914.	927.	914.	995.	1020.	1153.	1228.	1035.1
ENERGY GWH	810.	688.	696.	663.	675.	645.	652.	675.	654.	734.	770.	830.	8493.4
ENERGY AV MW	1088.	1024.	935.	921.	907.	896.	876.	907.	909.	987.	1070.	1115.	969.6
*L.F. %	93.7	90.6	88.6	95.0	95.1	98.0	94.6	99.3	91.3	96.7	92.8	90.8	93.7

* LOAD FACTOR BASED ON 1 HOUR PEAK

JAN 19/89

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON THE LOAD FORECAST REPORT NO. 881212

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	AVERAGE OR TOTAL
2009													
20 MIN PEAK MW	1163.	1134.	1057.	974.	957.	917.	927.	914.	998.	1024.	1156.	1235.	1037.9
1 HOUR PEAK MW	1160.	1129.	1053.	966.	950.	910.	923.	910.	992.	1017.	1152.	1228.	1032.4
ENERGY GWH	811.	690.	696.	663.	674.	645.	651.	675.	654.	735.	771.	831.	8495.6
ENERGY AV MW	1090.	1026.	935.	920.	906.	895.	875.	907.	908.	987.	1071.	1117.	969.8
*L.F. %	93.9	90.9	88.8	95.3	95.4	98.4	94.9	99.7	91.5	97.1	93.0	91.0	93.9
2010													
20 MIN PEAK MW	1163.	1134.	1056.	971.	954.	914.	923.	910.	995.	1022.	1156.	1236.	1036.2
1 HOUR PEAK MW	1160.	1129.	1052.	963.	947.	907.	919.	906.	990.	1015.	1152.	1229.	1030.7
ENERGY GWH	813.	690.	696.	663.	675.	645.	651.	675.	654.	736.	773.	834.	8505.8
ENERGY AV MW	1093.	1027.	936.	921.	907.	895.	875.	907.	908.	989.	1074.	1121.	971.0
*L.F. %	94.2	91.0	89.0	95.6	95.8	98.7	95.2	100.1	91.7	97.4	93.3	91.2	94.2

* LOAD FACTOR BASED ON 1 HOUR PEAK

FORECAST PERFORMANCE

6.0 PERFORMANCE OF LOAD FORECAST 881212 in 1988

6.1 Actual Primary Demand Versus Forecast

The Short-Term Primary Load Forecast (881212) was prepared using regional estimates commencing January 1988. Since no 1988 actual data are used in this key component of the forecast process, it is worthwhile monitoring current year actuals to see how well the forecast is tracking. This section compares the forecast of system demand and customer loads with the actuals for 1988.

Table 6.1: Actual Total System Primary Demand Versus Forecast

	1-Hour Peak - GW					Energy - TW.h				
	Actual		% Yr/Yr	1988 Forecast	% *	Actual		% Yr/Yr	1988 Forecast	% *
	1987	1988	Growth	881212	Dev.	1987	1988	Growth	881212	Dev.
Jan	20.3	22.3	9.9	22.3	0.0	11.9	12.9	8.7	13.0	-0.8
Feb	20.4	21.6	5.8	21.4	0.6	10.9	12.3	12.3	11.9	3.3
Mar	19.4	20.3	4.5	20.9	-3.0	11.1	12.2	9.6	12.0	1.6
Apr	17.9	17.9	0	18.7	-4.4	9.7	10.4	7.0	10.4	0.5
May	17.2	17.8	3.7	17.5	2.0	9.6	10.0	4.5	10.3	-2.9
Jun	17.9	18.8	5.2	18.1	4.3	9.9	10.1	2.6	9.9	2.1
Jul	18.2	19.2	5.7	18.4	4.8	10.3	10.6	3.0	10.3	3.4
Aug	18.5	19.5	5.1	18.8	3.6	10.0	11.0	9.7	10.5	4.4
Sept	16.5	16.9	2.5	17.6	-4.2	9.5	9.8	2.5	9.9	-1.1
Oct	17.8	18.4	3.2	18.5	-0.7	10.5	10.9	3.5	10.7	1.5
Nov	19.7	19.9	1.0	20.9	-4.8	11.0	11.4	3.2	11.5	-1.1
Dec	20.4	22.9	12.2	22.5	1.7	11.9	12.8	7.3	12.6	1.4
Avg	18.7	19.6	5.0**	19.6	-0.1**	126.5+	134.4+	6.3**	133.1	1.0**

* Percent deviation from forecast.
** Based on annual average
\+ Total

The hot and humid weather during the summer of 1988 resulted in a higher-than-forecast peak for the months of June through August. In September, the peak forecast for air-conditioning never materialized due to the unusually cold weather during the first part of the month. On the other hand, the November forecast for peak heating load was never attained because of the mild weather.

During the month of August, a combination of both above and below weather effects was experienced which resulted in net energy load growth of 4.4% more than predicted.

6.2 Weather-Corrected Primary Demand Versus Forecast

As Load Forecast 881212 assumed normal weather in estimating one-hour peak and energy, weather-corrected load data for 1988 provide a better test of forecast performance than actual data which, as noted above, are subject to a variety of weather influences. Weather had little effect on the aggregate accuracy of both the peak and the energy demand forecast in 1988 as can be seen from Table 6.2.

Table 6.2: Weather-Corrected Total System Primary Demand Versus Forecast

	1-Hour Peak - GW					Energy - TW.h				
	Weather Corrected Demand		% Yr/Yr	1988 Forecast	% *	Weather Corrected Demand		% Yr/Yr	1988 Forecast	% *
	1987	1988	Growth	881212	Dev.	1987	1988	Growth	881212	Dev.
Jan	21.1	22.5	6.6	22.3	0.9	12.2	13.2	7.7	13.0	1.5
Feb	20.7	22.2	7.4	21.4	3.5	11.0	12.2	11.1	11.9	2.8
Mar	19.2	20.4	6.0	20.9	-2.4	11.4	12.2	6.9	12.0	2.3
Apr	17.8	18.6	4.0	18.7	-0.9	10.0	10.4	3.6	10.4	0.1
May	16.5	17.3	4.8	17.5	-0.9	9.6	10.2	5.8	10.3	-1.1
Jun	17.3	17.9	3.4	18.1	-1.0	9.7	10.0	3.6	9.9	0.8
Jul	17.4	17.9	2.9	18.4	-2.2	10.0	10.2	1.6	10.3	-0.9
Aug	17.4	18.3	5.0	18.8	-2.5	10.0	10.6	5.8	10.5	0.8
Sept	17.1	17.4	1.8	17.6	-1.5	9.7	10.0	2.9	9.9	1.0
Oct	17.7	18.6	4.9	18.5	0.2	10.4	10.5	1.1	10.7	-2.1
Nov	20.5	21.0	2.4	20.9	0.5	11.1	11.6	3.7	11.5	0.1
Dec	21.4	22.3	4.4	22.5	-1.0	12.3	12.9	4.6	12.6	2.9
Avg	18.7	19.5	4.6**	19.6	-0.6**	127.6+	134.1+	5.1**	133.1+	0.8**

* Per cent deviation from forecast.
** Based on annual average
\+ Total

6.3 Diversity and Losses

System customers are billed on their maximum monthly peak load, whenever in the month it may occur (the non-coincident peak load). This quantity will be equal to or greater than that customer's load at the time of system peak (the coincident load). Diversity is defined as the coincident load minus the non-coincident peak load. It is, therefore, zero or negative because diversity reduces system peak demand. Diversity for individual system customers can only be measured at the time of system peak.

System peak losses are the difference between system peak and the sum of customers coincident loads, and system energy losses are the difference between energy sent out by the system and that received by the customers. It is not possible to allocate losses to individual customers. Losses are positive because they increase system demand.

For peak demands, the term net diversity and loss refers to the sum of the two.

Relationship Between System Demands and Customers Loads - 1988

The performance of Forecast 881212 on an average monthly basis was as follows:

Table 6.3: Performance of Forecast 881212

Average Peak MW*	Actual 1987	Actual 1988	Increase MW	Increase %	1988 Forecast 881212	Deviation from Forecast MW	Deviation from Forecast %
System Demand	18690	19632	942	5.0	19642	-10	0
Customer Loads	19110	20111	1001	5.2	20042	69	0.3
Net Diversity & Losses	-420	-479	-59	14.0	-400	-79	19.8
% Customer Loads	-2.2	-2.4			-2.0		
Energy TW.h							
System Demand	126.5	134.4	7.9	6.2	133.1	1.3	1.0
Customer Loads	121.0	128.6	7.6	6.3	127.2	1.4	1.1
Losses	5.5	5.8	0.3	5.5	5.9	-0.1	
% Customer Loads	4.5	4.5			4.6		-0.1

* 1 Hour

Line losses in percent of customer energy and peak were very close to the 1988 forecast, 4.5 and -2.4 compared to 4.6 and -2.0, respectively.

6.4 Unallocated Load

Since the forecast is the sum of the Regional estimates and the unallocated load that is eventually decided upon, the "actual" unallocated load is that which would have reduced the forecast error to zero.

Table 6.4: Average Monthly Results for 1988

Unallocated Load	Peak MW	Energy Av. MW
Forecast	144.4	109.9
"Actual"	213.0	272.3
Error (Actual-Forecast)	68.6	162.4

6.5 Detail of Customer Loads

(1) By Class

The monthly average results in terms of growth from 1987 and deviation from forecast are shown below:

Table 6.5.1: Sum of Customers' Loads (By Class) - 1988

1988 Average		Increase Over 1987		Deviation From F/C No. 881212		Unallocated Load Forecast
		MW	%	MW	%	MW
Total	- Peak	996	5.2	69	0.3	144.4
	- Energy	829	6.0	207	1.4	109.9
Municipal	- Peak	738	5.6	53	0.4	176.1
	- Energy	606	6.4	132	1.3	127.8
Retail	- Peak	190	6.4	30	1.0	-2.3
	- Energy	186	9.7	89	4.4	-1.4
Direct	- Peak	69	2.2	-15	-0.5	-29.3
	- Energy	37	1.5	-14	-0.6	-16.5

(2) By Region

Table 6.5.2 Sum of Customers' Loads (By Regions) - 1988

1988 Average		Increase Over 1987		Deviation From F/C No. 881212		Unallocated Load Forecast
		MW	%	MW	%	MW
Total	- Peak	996	5.2	69	0.3	144.4
	- Energy	829	6.0	207	1.4	109.9
Central	- Peak	547	6.1	38	0.4	103.2
	- Energy	432	6.6	78	1.1	76.4
Western	- Peak	184	4.8	39	1.0	27
	- Energy	144	5.1	39	1.3	21.2
Eastern	- Peak	112	4.4	-34	-1.3	14.9
	- Energy	117	6.6	20	1.1	12.1
Geo. Bay	- Peak	62	5.5	16	1.4	-1.6
	- Energy	53	7.0	37	4.8	-0.8
N. Eastern	- Peak	56	3.5	9	0.5	0.5
	- Energy	46	3.8	16	1.3	0.8
N. Western	- Peak	35	3.8	-1	-0.1	0
	- Energy	37	5.0	18	2.4	0

Reasons for varying growth rates over 1987 and deviation from forecast are diverse, but may generally be realted to economic conditions in 1988.

Further chronological and regional class detail are available in the attached tables.

UNCERTAINTY BAND

7.0 UNCERTAINTY IN THE LOAD FORECAST

7.1 Introduction

The recommended long-term load forecast is based on analysis of the results obtained from the EEMO and End-Use models and the application of judgement. However, the complexity of these models, while being an advantage for purposes of producing a recommended forecast, means that they are inappropriate as tools for developing uncertainty bands around that forecast.

Up until now these uncertainty bands have been calculated from analysis of past forecast errors. In order to estimate forecast error standard errors more than ten years in the future, the trend in the first ten years' errors was extrapolated out to the forecast horizon. Because of the large ten year ahead forecast errors made in the 1970's, this methodology produced very wide error bounds on the long-term forecast. Not only are these of limited use for planning purposes but there is good reason to believe that past forecast errors may not be the best guide to the error bounds for current and future forecasts.

For this reason, therefore, an attempt was made during the preparation of the 1988 long-term forecast to develop an alternative methodology for estimating load forecast uncertainty. The objective was to develop a technique which was predicated on a minimum number of assumptions. The investigation focussed on small multiple equation systems and various single equation models of the growth of electricity consumption in Ontario.

In the adopted procedure the determination of the uncertainty in the load forecast is decomposed into the uncertainty associated with economic growth in Ontario and that associated with future trends in the pattern of electricity consumption. This is done via a stochastic simulation procedure which generates the probability distributions of these two dimensions of uncertainty using two empirically constructed Variable Elasticity Models - for load growth and economic growth.

7.2 The Economic Growth Model

The economic growth model relates real Ontario GDP to population and has its basis in the Neo-Classical Economic Growth Model[1].

$$\log(GDP) = \underset{(13.2)}{0.605*\log(POP_t)} + \underset{(14.9)}{0.0085*[\log(POP_t)]^3} + e_t$$

This equation was estimated using data for the period 1927 to 1987[2]. The model has good out-of-sample forecasting properties - the average error for the period 1976 to 1987 was -0.39% - and produces a median forecast for the period 1988 to 2010 which agrees very well with both the most likely forecast prepared by the Economic Forecasts Section and with the results of a survey of other

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[1] Keng, C.W. Kenneth (1988), "Forecasting Energy Demand with Variable Elasticity Models', Mimeograph, Economics & Forecasts Division, Ontario Hydro, Toronto, Ontario, Canada.

[2] Ontario to GDP for 1927 to 1960 was constructed from national data using historical relationships between Ontario and Canada.

forecasting professionals prepared for the external review of the load forecast. The median forecasts of the long-term growth rates from these sources are shown below.

GDP Growth
(Annual Average, 1988-2010)

Model	2.5%
Official Forecast	2.7%
Survey	2.7%

In order to produce an uncertainty band around the GDP forecast, a measure of the uncertainty in the future population growth was required. Using the data for 1927 to 1987, 23 average annual compound growth rates were calculated from data ranging from 1 to 23 years apart. These results in turn yielded a set of 23 standard deviations which could be applied to each of the 23 years in the 1988-2010 forecast period. Before doing so, however, they were adjusted using the ratio of the calculated mean historical growth rate to the growth rate of the exogenous official forecast of population growth. For the forecasting horizon, the 1 to 23 year ahead compound growth rates are assumed to be independently normally distributed with mean equivalent to the exogenous official forecast and standard deviations equal to the adjusted historical standard deviations.

7.3 The Energy Model

The energy model relates annual Ontario Hydro system energy in average megawatts to real GDP in Ontario in 1981 constant dollars. The estimation period was 1962 to 1987.

$$\log(ENERGY_t) = -32.5 + 5.93*\log(GDP_t) - 0.20*[\log(GDP_t)]^2 + e_t$$

The standard error of the equation at the mean is 268 average megawatts and the R-Bar squared is 0.994.

As with the model of economic growth, this model has excellent out-of-sample forecasting properties - the average error for the period 1976 to 1987 is 1.16% - and it produces a median forecast growth rate for the period 1988 to 2010 of 2.6%, which is quite close to the official load forecast growth rate of 2.4%.

7.4 Stochastic Simulation of GDP and Energy

As was mentioned above the energy model is of the form:

$$ENERGY_t = \exp(a + b*\log(GDP_t) + C*(\log(GDP_t)^2) + e_t)$$

Forecasts of ENERGY can be generated as conditional expectations of the above equation given values for GDP_t. Thus, given a sample drawn from the distribution of GDP, we can generate a sample for ENERGY whose stochastic properties are implied by those of GDP.

This procedure was carried out as follows. First, standard Monte Carlo simulation methods were used to draw 1000 samples from the assumed distribution of Ontario population for every year of the forecast period. Then, using this data, the economic growth model was simulated yielding 1000 samples of GDP for

each forecast year. Finally, and in the same fashion, the energy model was simulated giving 1000 samples of Ontario Hydro energy for each year. These simulated samples were then used to produce distributions for population, GDP and load.

7.5 Estimated 80% Confidence Intervals for GDP and Annual System Energy

As previously mentioned the economic growth model produces a median forecast which is consistent with both the official economic outlook and the survey of outside forecasters. The latter group was also asked for their subjective estimate of the 80% uncertainty band for GDP for the period to 2010. A comparison of this, and the corresponding uncertainty range produced by the simulated model, is shown below.

80% Uncertainty Band for Ontario GDP
(Annual Average Growth Rates, 1988-2010

	Lower (10%)	Median (50%)	Upper (90%)
Model	1.7	2.5	3.3
Survey	1.7	2.7	3.6

While this comparison is not meant to imply anything about the 'correctness' of the model results it does tend to indicate that the model is 'reasonable'.

The 80% confidence interval for system energy is reproduced in section 2 on table 2.1.8[3]. The results have been adjusted, from those produced by the actual simulation, so that the median corresponds to the official forecast. The required adjustments are shown in the table below.

Required Adjustment

Year	TW.h	Percent
Short-Term		
1988	-0.5	-0.3
1989	-2.6	-1.9
1990	-5.4	-3.8
1991	-6.9	-4.8
1992	-7.6	-5.1
1993	-8.7	-5.6
Long-Term		
1995	-13.0	-8.0
2000	-16.6	-9.0
2005	-14.6	-7.2
2010	-12.0	-5.5

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[3] The simulation procedure used requires minimum distributional assumptions - only the population growth rates are assumed to be normally distributed. For this reason, while complete distributions for the forecasts of energy and GDP are available, persons requiring these are requested to contact the Load Forecasts Department rather than attempting to estimate them for themselves.

These results indicate that, compared to the official forecast, the model tends to over-predict and that the extent of this over-prediction is greatest in the period from the mid-1990's to 2000. However, at no time in the period of the forecast does the required adjustment exceed 10% of the official load forecast. So, even though the purpose of the two equation system developed here was to estimate the uncertainty about the load forecast, the fact that it also tracks the official forecast well lends greater confidence to the bandwidth produced.

NEW END-USE MODELS

8.0 NEW END USE MODELS

In addition to work on the existing end-use model, extensive work was carried out on a new generation of end-use forecasting models obtained from EPRI called REEPS (residential), COMMEND (commercial) and INDEPTH (industrial). The models were developed by EPRI for use by utilities throughout the United States. During the last two years, Ontario Hydro has put in a considerable effort towards developing Ontario-specific data bases and calibrating the models to more accurately reflect energy usage patterns in the Ontario market.

Ontario Hydro turned to these models since they provide a level of sophistication beyond the simplistic "accounting approach" utilized by the existing model. The choice, energy efficiency and utilization of electricity consuming equipment are modelled directly by these models using basic economic principles of cost minimization and consumer behaviour. In addition, fuel prices are an explicit input. Neither of these two properties are present in the current model.

Further adaptation and enhancement of these models will play a major role in future work programs. The defendable analysis of the impact of Demand Side Management programs is a key aim of this work.

8.1 REEPS Forecast

REEPS, the Residential End-Use Energy Planning System is a micro-simulation forecasting model of residential energy demand. Using a representative sample of household observations, REEPS simulates both (1) appliance purchase decisions and (2) efficiencies and utilization patterns for each of nine end-uses plus a residual category. These decisions are based upon information regarding household and dwelling characteristics, fuel prices and availability, weather patterns, and appliance attributes. This type of microsimulation explicitly acknowledges diversity within a population. That is, different households in different situations will respond differently to a given conservation strategy or fuel price increase.

As referred to above, REEPS uses a representative sample of household observations. This sample was based upon a large survey conducted by the Market Planning Dept. The survey (known as the Residential Appliance Survey) was conducted in 1986 with mail-out questionnaires being responded to by approximately 50,000 households throughout the province. The responses provided the base on which the model simulation occurs.

REEPS requires forecasts of exogenous parameters such as the number of households, persons per household, age of head of household, fuel prices, income per household etc. As with the End Use model these forecasts were developed by the Economic Forecasts Section and adapted to the REEPS environment by the Load Forecasts Dept.

The decisions regarding the type of space heating and air conditioning systems to install are highly interdependent with that for central air conditioning. As well, other appliance purchase decisions tend to be dependent upon the space heating system choice. For example, water heating and, to a lesser extent, cooking and clothes drying appliance choices are often made in light of the space heating choice. In order to capture this interdependence in the

appliance choice equations, the space heating, air conditioning, water heating and cooking decisions are modelled jointly by REEPS.

For space conditioning (heating and air conditioning), the determination of electricity demand is analyzed by examining two separate, but related, forecasts: penetration of electricity and unit energy consumption associated with the equipment.

By the year 2010, approximately 24% of all single family housing is forecast to be electrically heated. Currently, the level is roughly 15%. This increase is caused by a combination of events. First, the price of electricity is predicted to decline in real terms over the forecast period (-0.21% p.a.). On the other hand, natural gas, electricity's chief competitor, is forecast to have positive real growth of approximately .84% p.a. Oil, already a decreasing market, has a similar price increase as natural gas, about .66% p.a. These differing fuel price forecasts account for about 75% of the shifting share forecast. Secondly, real household income is predicted to increase by 0.8% p.a. to the year 2010. REEPS' model parameters are consistent with recent trends that show that as income per household rises, consumers are either (1) more willing to pay the higher initial capital costs of an electric centrally heated house (furnace) or (2) the higher operating costs associated with heating with baseboard heating. (Note that although the price growth rate patterns are different for the three fuels, natural gas is still the cheapest in relative terms). Furthermore, a significant portion of the households that choose electric space heating will use a heat pump (approximately 20% of the electrically heated houses in 2010). Heat pumps offer advantages both because of their dual heating/cooling capability and because of their high operating efficiency levels.

As mentioned above, the second determinant of electricity demand due to space heating is the actual consumption level of the equipment in use. REEPS explicitly recognizes that the annual energy consumption of any appliance is determined both by its efficiency level and its utilization rate. For space heating, the average single family house currently uses about 18,000 kW.h of electricity per year. By 2010, efficiency improvements in space heating equipment combined with improvements to shell design will are estimated to cause an overall decrease in average space heating requirement of about 11%. That is, the amount of electricity required for space heating for an average conventionally heated house would be roughly 16,400 kW.h per year. This implied efficiency improvement is slightly higher than that of the existing end-use model which predicts that the average space heating electricity requirement will decrease to roughly 16,900 kW.h per year.

In summary, the combined effects of increasing penetration for electric space heating and decreasing unit energy demand of the the equipment will cause electricity demand due to space heating to increase from its present level of 7400 GW.h to 13900 GW.h. Note that if average unit energy demand remained at the 1986 level, the electricity consumption for space heating by 2010 would have been 17200 GW.h.

Because of the interdependence between space heating and air conditioning, the strong growth in electricity share for space heating (especially heat pumps), necessarily implies that air conditioning penetration will also increase. Currently, about 18% of all single family houses have central air conditioning

(note that apartments are not included in this analysis). This contributes roughly 830 GW.h to yearly energy demand. By the year 2010, REEPS predicts that 50% of all houses will have central air conditioning accounting for 3330 GW.h of electricity demand.

For room air conditioning, a different picture is envisioned. Currently, the level of penetration for room air conditioners is approximately 19%. By the year 2010 it is expected that the level will be about 13%. Electricity demand is expected to fall as a result from the current level of 260 GW.h to 228 GW.h by 2010.

The relatively high penetration rate of central air conditioning is driven by the fact that in the current version of REEPS there is a strong relationship between central air conditioning acquisition decisions and both electricity price and household income. Both of these variables are expected ot have growth paths that would favour more electricity usage (ie. low electricity price and high income). Room air conditioning penetration rates, on the other hand, will fall as more single family households choose the more efficient central systems.

REEPS also examines the energy used by 7 other major residential appliances. These include: water heaters, refrigerators (first and second), freezers, dishwashers, room air conditioners, stoves plus a residual category which accounts for all other electricity use in the household. In 1986, appliances (excluding water heaters) accounted for about 18,500 GW.h of the total residential electricity demand of 32,700 GW.h or about 57% of demand. For the forecast period, it is expected that energy demand from these same appliances will be about 29,100 GW.h, with the total residential demand being 51,900 GW.h. Appliance contribution to total demand, therefore, is forecast to remain constant at about 56%. This percentage is not expected to undergo significant change for a number of reasons. First, many electric appliances are beginning to reach saturation levels and thus their penetration rates, although continuing to increase, are doing so more slowly. Second, average appliance efficiency is increasing. In fact, efficiency improvements of as much as 30% over the current stock levels are predicted for some of these appliances, though these efficiency improvements are offset in part by greater usage of the stock. Lastly, as mentioned, both electric space heating and air conditioning are forecast to have strong growth paths and thus account for a larger portion of the total electricity demand.

For electricity use per average Ontario household (regardless of space heating fuel) REEPS predicts a gradual increase from the current level of 13,300 kW.h per house to about 14,200 kW.h per house in 2010. As outlined above, this growth in intensity is driven by increases in market share in areas where electricity competes with other fuels (ie space heating), increases in the penetration rates for electricity using devices, and increased usage of existing equipment.

A comparison between REEPS and the existing end-use model reveals that the two models predict very similar growth patterns for electricity demand (2.0% p.a. for REEPS vs 2.1% p.a. for the existing model). Although the results of the two models are very similar (implying that an engineering model can do an adequate job), the additional richness of decision-maker behaviour analysis makes the REEPS approach to energy analysis a very attractive one. As well,

the End-use model's input assumptions already reflect some of the insight gained by using REEPS.

8.2 COMMEND Forecast

The central energy equation in COMMEND for a single building/end-use segment defines energy use as the product of floorstock, fuel share and energy use index (EUI):

(1) ANNUAL ENERGY USE = F * S * EUI

where F = square footage of floorstock
S = average share of space served by the end-use and fuel
and, EUI = average energy index use for served space

Note that the value of each of these three factors can change over time.

The energy use equation is modelled separately across 12 building segments that comprise the Ontario commercial sector. In each segment, three fuel types (electricity, natural gas and oil) are examined for eight different end-uses. These end-uses are space heating, cooling, lighting, cooking, water heating, refrigeration, ventilation, and a miscellaneous category which covers all other end-uses.

Floorstock data is regarded as the best indicator of the amount of energy-using equipment and activities in the commercial sector. The forecast of floorspace is performed exogenously to the model by the Economic Forecasts Section and embodies the assumptions about growth in economic and demographic variables such as employment, output, and population that are consistent with the aggregate economic outlook.

The other two variables in the central equation, fuel shares and EUI values, reflect the outcome of decisions made with respect to energy equipment options. These decisions include the extent of floorspace seviced by each end-use (determines penetration), the generic technology (determines fuel share), and the specific technology (determines EUI).

Fuel share levels for each building type and end-use consist of two separate, but related estimates. Firstly, penetration rates for each end-use in each building type are estimated, with 100% share given to the end-uses of heating, lighting, and miscellaneous. Secondly, once the penetration rates are established, fuel shares are assigned to each end-use. Clearly, only end-uses which use more than one fuel require these estimates. For example, water heating penetration in schools was first established in total, then the share of the heating was assigned to the three available fuels. Thus, for schools the penetration of water heating could be 75% and the fuel share 25% oil, 25% gas and 25% electricity.

All fuel share estimates are based upon information supplied through in-house sources (Market Research and Load Forecast Departments) and estimates obtained from various outside agencies. The EUI embodies both average equipment efficiencies and average usage levels across the customer base in each subsector. EUI values differ across end-uses, building types and fuels, reflecting the differences in equipment efficiencies, thermal features of buildings,

and usage levels. Usage levels for an end use are determined by the cost of energy services (ie, fuel prices or equipment efficiencies). There are separate EUI values for existing floorstock as well as marginal values for new construction and replacements.

For new construction and replacements, decisions on energy technologies can be modelled in a variety of ways. Heating is an end-use where fuel competition and efficiency choice are very important. COMMEND uses a life-cycle cost minimization approach to simulate decision-maker choices with respect to heating fuel shares and HVAC (heating, ventilation, and air conditioning) efficiency choices in new construction and replacement decisions. The major drivers for efficiency and fuel choice are the decision maker's discount rate and price expectations.

For end-uses other than heating, cooling and ventilation, EUI response to energy prices for new construction and replacements are captured by using an elasticity approach. This occurs both in terms of response related to efficiency choice and response due to utilization characteristics. For all end-uses except heating, marginal fuel shares are input to COMMEND and remain fixed throughout the forecast period.

The link between fuel shares, and EUI can be demonstrated from a price change. An increase in electricity price for example, will cause a decision maker to re-evaluate his technology choice while reducing the usage of his electricity using appliances. Electricity use follows this path until the first replacement year. At that time, a more efficient replacement is installed (natural gas fuel share may rise at the expense of electricity's), which causes a drop in the amount of electricity the decision maker uses per square foot of floorstock (ie, EUI value decreases). Utilization in the replacement year increases since the price of energy services declines. This is a result of efficiency improvements exceeding real price gains.

By the year 2010, COMMEND predicts the commercial sector will consume approximately 64.9 TW.h of electricity, up from a 1987 forecast level of 35.4 TW.h. This represents an annual growth rate of about 2.7%.

The 2.7% growth rate in electricity demand is considerably higher than that of floorspace (1.0%), implying an increasing overall trend towards high electrical intensity per square foot of floor area (see figure below). Electrical intensity is expected to grow at an annual rate of 1.7%, rising from 14.4 kW.h-/sq.ft to 21.2 kW.h/sq.ft. The main causes of this increase in intensity are:

(1) increased penetration of electric space heating;
(2) higher penetration of miscellaneous electricity using devices (including air conditioning);
(3) increased usage of existing equipment;
(4) change in sector building mix (ie, a shift towards building types which have higher electricity intensity).

For heating, electricity's share of the market is projected to increase from a 1987 level of about 13% of stock to 31% of stock by 2010. The resulting growth in electricity demand due to these share increases will be partially offset by improvements in electric heating efficiency. Heating efficiency improves as the result of more efficient heating devices (such as heat pumps) and improved

building envelope. For miscellaneous equipment use, high penetration rates combine with limited electrical efficiency improvements to produce a forecast of approximately 3% per year growth in electricity from a 1987 level of 7.7 TW.h to approximately 16.2 TW.h by 2010.

COMMEND's results were compared to the existing commercial model. All exogenous forecasts (fuel price, floorspace, etc) were the same for each model. The resulting electricity forecasts, however, are somewhat different. COMMEND predicts a yearly growth rate for electricity of roughly 2.7%. The existing model forecasts a rate of 2.2% over the same period. The main differences are in the space heating and miscellaneous use categories. COMMEND's modelling structure is such that fuel price plays a very important role in the determination of space heating choice. With electricity's favourable fuel price forecast, electric space heating share grows at more than 4% per year. For miscellaneous uses, COMMEND predicts that electricity demand for these uses will more than double over the forecast period. In light of recent observations, COMMEND may actually more accurately reflect commercial sector behaviour. Further investigation into commercial sector energy patterns will attempt to make this determination.

8.3 INDEPTH Forecast

Ontario Hydro is currently completing its involvement in the demonstration phase of EPRI's new INDEPTH (Industrial End-Use Planning Methodology) model. As part of its role as a test utility, Ontario Hydro has developed process models of the cement, iron and steel and pulp and paper industries. This research effort included the development of extensive databases containing the operating and cost data necessary to run these models.

INDEPTH provides a flexible framework for load forecasting and the analysis of demand side management programs, allowing the analyst to include much greater detail than is possible in the existing end-use model (EUM). Each industry is defined in terms of a number of processes, each process having various competing technologies available to accomplish the task at hand. Technologies are selected on the basis of minimum life cycle cost, unlike the EUM which relies strictly on the analyst's judgement. This approach requires that the capital cost, operating cost and energy consumption be specified for each technology as well as various financial parameters such as the discount rate. The analyst is able to test the sensitivity of the most-likely forecast by running the model using different input assumptions (e.g. future energy prices). Forecasts of the main products of each industry are produced outside the model.

To date, only the cement model has been calibrated and tested. Using this model, electricity consumption is forecast to decrease to 1990 due mainly to reduced production. This is followed by relatively smooth growth averaging 1.8% per annum over the remainder of the forecast period. It is expected that "dry" technology will be used in all new plants rather than the older "wet" technology, thus raising the average electricity intensity. More efficient grinding mills and high efficiency motors will more than offset this increase, however, leading to an overall intensity decrease of approximately 10% by 2010. Improved particle classifiers, which reduce the amount of grinding required, do not yet appear to be economic based on present technology.

Over the next year, the iron and steel and pulp and paper models will also be calibrated and tested in time for next year's forecast. Work will also begin on an industrial chemicals model, for which data has already been collected, and a mining, smelting and refining model. By the time all five models are operational, they will cover 60% of Ontario's industrial electricity demand.

Table 8.3: INDEPTH CEMENT FORECAST

	Electricity Forecast (GW.h)	Cement Production (000 tonnes)	Electricity Intensity (kW.h/tonne)
1987	756	5733	132
1990	685	5405	127
1995	754	6208	122
2000	851	7034	121
2005	930	7700	121
2010	979	8123	121
		GROWTH RATES	
1987-2000	0.9%	1.6%	
1987-2010	1.1%	1.5%	
1990-2010	1.8%	2.1%	
2000-2010	1.4%	1.4%	

DEFINITIONS

9.0 GLOSSARY

9.1 Demand (Versus Load)

Demand means the electrical output from the Corporation's generating resources together with outside purchases required to supply the load of the Corporation's customers. In this report demand refers to the level of demand at the generating stations, while load refers to the flow of electricity at the wholesale billing points. Each term refers to peak or energy as specified in context.

Power means an instantaneous time rate of delivery of energy. Peak refers to the power averaged over a short period during which time the load is at its maximum. Energy demand is the accumulation of power over time, which results in an amount of useful work (or heat, lighting etc.)

In this report energy is reported in units of terawatt-hours or else in average megawatts. To obtain average megawatts for a period of time, the megawatt-hour figure is divided by the number of hours in the period.

Annual and Winter Peak Demand

All peak demands shown in this report incorporate the effects of typical weather conditions associated with the monthly peak demands. Under these conditions the annual peak demand occurs in December and the winter peak normally occurs in January.

Primary Peak Demand

Primary Peak Demand is the total generated and purchased minus secondary sales.

Secondary sales is power provided at the convenience of Ontario Hydro on a non-contractual basis usually to interconnected utilities. This element is not forecast in this report.

Primary Demand in Terms of Generation

Primary Peak Demand is the sum of the customers' peak requirements (not necessarily coincident with the system peak) adjusted by an allowance for diversity and losses. This figure gives the primary peak demand at the level of the generating stations.

- **Peak** - The figures shown are those for the time of the maximum 1-hour or 20-minute peak demand.

  An allowance for the weather effect expected on the typical monthly peak day is incorporated into the Primary Peak Demand for each month. Diversity and losses are affected by extreme weather as well.

- **Energy** - Monthly energy demands shown in this report are expressed in terawatt hours and average megawatts, in order to give an immediate impression of load factor, and also to make successive monthly values independent of differences arising solely from the varying lengths of the months.

Ontario Primary Demands in Terms of Generation

East System

Includes:

The primary power and energy loads of Municipalities, Industrial Customers, and Retail Customers in Ontario within the geographic boundaries of the Central, Western, Eastern, Georgian Bay and Northeastern Regions, together with appropriate diversity and losses.

Power and energy delivered free of charge by Ontario Hydro to Spruce Falls Power and Paper Company Limited in compensation for the effects of Little Long Generating Station on the Company's Smoky Falls Generating Station.

Excludes:

Power and energy exported to the United States and the Province of Quebec. Also excluded are deliveries under exchange agreements, namely, to Fort Erie on behalf of the CNP Company, and to Cornwall on behalf of the St. Lawrence Power Company. In both of these cases the amount of power delivered is made up at another point on the system so that there is no resultant demand on the Corporation's resources.

The loads of retail customers in Hornepayne, although customers of the Northeastern Region, because they are supplied from power resources within the Northwestern Region.

West System

Includes:

The primary power and energy loads of Municipalities, Direct and Retail Customers in Ontario within the geographic boundaries of the Northwestern Region, and the loads of retail customers in Hornepayne together with appropriate diversity and losses. The latter customers are included because they are supplied from resources within the Northwestern Region.

Power and energy delivered free of charge to Boise Cascade Company (Kenora), as compensation for the effects of Whitedog Falls Generating Station on the output of its generating stations.

Excludes:

Power and energy exported by Ontario Hydro to the United States and the Province of Manitoba.

Power and energy delivered to Boise Cascade at Fort Frances in exchange for the output of the Company's Calm Lake and Sturgeon Falls Generating Stations.

Ontario primary demands (both East and West Systems) exclude the delivery of turbo replacement power to various paper companies.

9.1.1 Basic Load Forecast

The Basic Load Forecast shows what would happen to electricity demand if Ontario Hydro did not adopt new activities to affect electricity demand. However, the current Demand/Supply Options Study indicates that some future electricity needs of the province will be met by other means than by increasing supply. Ontario Hydro has programs to promote changes in the pattern of usage to allow some of the province's future electricity needs to be met by demand reductions.

9.1.2 Primary Load Forecast

The Primary Load Forecast takes into account the effect on Ontario Hydro demand of future Ontario Hydro activities designed to affect the level and shape of the load. It is derived by subtracting from the Basic Load Forecast the net effect of Load Displacement generation and Ontario Hydro's incentive-driven demand management programs which include:

(1) changes in rate structure such as time-of-use, off-peak incentives, etc;

(2) financial incentives such as grants or loans, etc.

It is the Primary Load Forecast which is to be used for supply planning purposes.

9.2 Diversity and Losses

Diversity is the difference between the sum of (individually metered) customer loads at the time of system peak and the arithmetic sum of the peak loads of all the customers regardless of whether they coincide with the system peak or not. Since individual customers experience their peak loads at diverse times, the arithmetic sum of their peak loads will be greater than the sum of customer loads at the time of system peak, and therefore the value for diversity is always negative.

Losses are the sum of electrical losses and consumption incurred in transmitting the electricity from the generating stations' terminals to all the customer metering points. This is evaluated by taking the difference between customer loads and system demands measured at the generating stations.

The figure for diversity and losses together will be positive if losses exceed diversity, and negative when diversity exceeds losses.

Diversity is a function of the timing of end-use utilization which is affected by social patterns and weather conditions. Losses are due mainly to transmission line loadings determined by system configuration and operation. System operation depends on hydraulic generation resources, export and circulating power flow, outages, etc.

There is no diversity in energy demand. The difference between the primary energy and the energy delivered to customers is losses.

9.3 Customers' Loads

Customers' Loads are the maximum peak loads of system customers which include cost contract municipalities, industrial customers and retail customers. Estimates of these loads are provided by the Regional Marketing Managers. The totals of these non-coincident customers' loads are referred to as the sums of customers' loads with appropriate qualifications for regional and other classifications.

The forecasts of Area loads in this report conform to the Power Billing Department, Customer Service Division practice of obtaining Area loads by summing the non-coincident loads of the D.S.'s supplying it.

9.3.1 Firm Loads

Firm Loads are supplied as required by the customer at all times as far as physical conditions permit.

9.3.2 Capacity Interruptible Loads

In general, capacity interruptible loads are those which can be interrupted under contract provisions which exchange interruptibility for the lower rates. Capacity interruptible power is the only class available. This class of power is available only for loads which can be reduced by at least 5,000 KW during interruption periods.

The sum of interruption periods shall not exceed the following:

(1) In any month up to 15% of the total time in the month.

(2) In any year up to 10% of the total time in the year.

(3) In any 5 consecutive years up to 5% of the total time in the 5 year period.

The purpose of supplying this class of power is to enable Ontario Hydro to reduce the generation reserves it would otherwise provide for, and to serve as a means of system relief under emergency conditions and other unpredictable circumstances.

Interruption Periods - (applicable Monday to Friday inclusive)

March to November inclusive - up to 5 hours per day
December, January and February - up to 14 hours per day

The customers' loads in this report are composed of the total firm and capacity interruptible. Therefore, in this report, the demands shown assume that rights of interruption under Capacity contracts are not exercised.

The amounts of power under contract within this class can therefore be regarded as being served out of reserve capacity planned for other purposes. No capacity is planned to meet interruptible loads.

As can be seen from the table under 1.2.4, 78 MW of capacity interruptible contracts are forecast to be added in the period of 1985-90. Due to the changing shape of the system duration curve and to diversity among these customers, the task of translating non-coincident interruptible loads into the

potential capacity savings from primary load cuts requires that allowance be made for diminishing effectiveness of successive increments of interruptible contract.

9.4 Standby Power

The Corporation has undertaken to supply standby power to the following customers who have their own generation.

Table 9.4: Standby Amount

Boise Cascade - Kenora	10.5	MW
Boise Cascade - Fort Frances	8.0	MW
Eddy Forest Industries Ltd	7.5	MW
Gananoque Electric Light & Water	1.25	MW
Canadian Pacific Forest-Driden (44 kV)	6.0	MW
Canadian Pacific Forest-Thunder Bay	17.1	MW
MacMillan Bloedel	1.8	MW

No specific allowance has been made for increases in the customers' load or system demands from standby requirements of customers.